From
S. Hatfield
10/03/94

Notes about CUWA implementation:

Dan Steiner put the San Joaquin measures together. He used the new San Joaquin model to look at the benefits. His thinking, and the benefits, as he explained them are as follows:

- The only way to really increase survival is with the barrier.

- Looked at increase in the survival index during the month the barrier was in, and found substantial benefit.

- Recommended flows of 2,000 to 5,000 because these flows are 'better than historical' and have the additional benefit of the barrier, also was concerned about flooding problem and water costs of higher flows without being sure of the benefit.

- Export constraints are also 'better than history' and the real effect of the barrier plus exports on Delta smelt is unclear. It is more important to put the barrier in and protect salmon, and this should allow more pumping, since the water would be coming from downstream where flows are no longer sensed by salmon. Dudley Reiser also suggested that monitoring for Delta smelt may be an important part of this.

My comments on these points and the measures:

1. From what we know now, we cannot assume the benefit of the barrier if don't include 1500 export constraints during the time it is in. Using a survival index goal makes it possible to increase exports in the future if the barrier functions well and does not cause problems.

2. At the time of the technical meetings, we were under the impression that the barrier could not be used to protect salmon. However, subsequent to the meeting we talked with the USFWS and together agreed that the barrier could be part of the protective measures for one month if exports were lowered to 1500 cfs. This substantially increased the protection which could be gained, especially in dry years, therefore we have increased our goal above the 2 to 3 times recommended in the Kimmerer paper.

3. The flow protection is substantially below DWRSIM base conditions overall. Even in critical years, the base case average is 1538 cfs, and the range is from 944 to 2218. Only two values are below 1,000 cfs (944 and 992). Although 1,000 cfs is a higher flow level than some years in the 1960's and 1970's, such conditions are no longer our target, since they were so poor.

4. Protection in wet years is very important - 5,000 cfs during the time the barrier is in and 1,000 during the rest of April and May does not protect higher flows important to the recovery and continued health of the population.

5. See Page with Table 3, Alternative Formulation paper for (very rough) estimate of CUWA implementation w/ San Joaquin model. However, this assumes base conditions remain the same (i.e. flows are not lowered to 1,000 cfs, and only those flows below 5,000 and 2,000 are changed upward, while those above that level remain the same. Not a good assumption in my mind.

Joaquin to protect vulnerable fish.

Implementation measures to attain the criteria would also include export restrictions during the time in April and May when the barrier is not in place. These would average 2000 cfs in critically dry years, 3000 in dry, 4000 in below normal, 5000 in above normal, and 6000 in wet years. With the sliding scale as currently formulated, the lowest flows (1977 hydrology) with the barrier in place would be approximately 2300 cfs if exports were kept at 1500 cfs.

One additional refinement to the implementation measures should be considered on the San Joaquin River. As discussed above, the Sacramento River criteria includes a ceiling value on the maximum salmon smolt survival. This was included because there appears to be a point where incrementally lower temperatures do not significantly increase salmon smolt survival. In theory, there may be a similar point on the San Joaquin River where incrementally higher flows in very wet years do not yield significantly higher salmon smolt survival. Nevertheless, the existing data do not suggest what those flow levels should be. EPA is considering another mechanism for dealing with this issue. EPA believes that in very wet years (those in which the flows exceed 10,000 cfs during the relevant period) it may be appropriate to require meeting the flow requirements associated with the targeted salmon smolt survival criteria index solely through natural storm events and restricted diversions, and not by upstream reservoirs releases. In other words, the implementation flows would be provided at these higher flow periods, if at all, by natural hydrology rather than by reservoir releases. In this way, the natural "flood events" that appear to be so beneficial to the salmon would be protected, but the water supply system would not have to bear the water costs of generating artificial flood events through reservoir releases.

i.e. flows must be passed through to the Delta if Vernalis flows exceed 10,000 cfs.

As indicated above, the USFWS model is the best available model of salmon smolt survival through the Delta, and EPA encourages the State Board to use the recently revised USFWS San Joaquin model as guidance for setting implementation measures. Nevertheless, it is important to recognize that there may be constraints on the model's use. Further monitoring and experimental releases under the chosen implementation regime are essential to verify and refine the model, and will insure that the smolts are actually surviving at the expected level. In addition, it will be particularly important to protect the base conditions assumed in the model, such as flows during the time the barrier is not in place, flows at Jersey Point, and temperature. The expected survival index is unlikely to be achieved if these base conditions deteriorate. As in the case of the Sacramento River criteria, EPA anticipates that at the time of the next triennial review enough monitoring data over a range of hydrological conditions will be available for a preliminary realize that these numbers are not survival estimates, but only indices, and that these indices have ranged up to 1.8 on the Sacramento and 1.5 on the San Joaquin (a Jersey Point release).

The workshop participants agreed that one option for setting survival criteria would be to characterize current (recent) survival indices separately under low and high flow conditions to provide a base for each separate set of conditions. Differentiating between low and high flow conditions also is consistent with the perception of workshop participants that substantially increased flows (and corresponding survival improvement) are relatively more achievable in drier years. Target index values for protecting the designated use could then be set by increasing the survival indices representing these two conditions (high and low flows) by a chosen incremental amount to provide increased protection, and scaling the goal to the 60-20-20 unimpaired San Joaquin water year flow index.[5]

In choosing the target criteria values for the San Joaquin, EPA relied in part on refining the target values included in the Proposed Rule, and in part on the workshop methodology outlined above.

EPA first developed a continuous function survival index target by refining the target values included in the Proposed Rule. To do so, EPA developed modeled index values associated with the implementation of protection measures proposed by USFWS. (USFWS, Measures to Improve the Protection of Chinook salmon in the Sacramento/San Joaquin River Delta, 1992; also known as WRINT-USFWS-7.) As indicated in the Proposed Rule, EPA believes that implementation of these measures is consistent with the protection of the designated fisheries uses. As explained below, however, EPA has revised its assessment of some of the implementation measures that are likely to be achievable, and this revision creates corresponding changes to the modeled index values. In addition, consistent with the findings of the workshop and with EPA's conclusions in the Proposed Rule, EPA increased protective measures in the drier years, and this increased protection is reflected in the modeled index values. Means of these modeled index values for each water year type are shown in Table 3. To translate these discrete index values into a continuous function, two lines of "best-fit" were created, one for the drier years (dry and critically dry) and one for the wetter years (wet, above normal, and below normal). By connecting these two lines, EPA created a

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[5] The San Joaquin water year index is the commonly-accepted method for assessing the hydrological conditions in the San Joaquin basin. It is also frequently referred to as the 60-20-20 index, reflecting the relative weighting given to the three terms (current year April to July runoff, current year October to March runoff, and the previous year's index) that make up the index.

# San Joaquin Hydrology

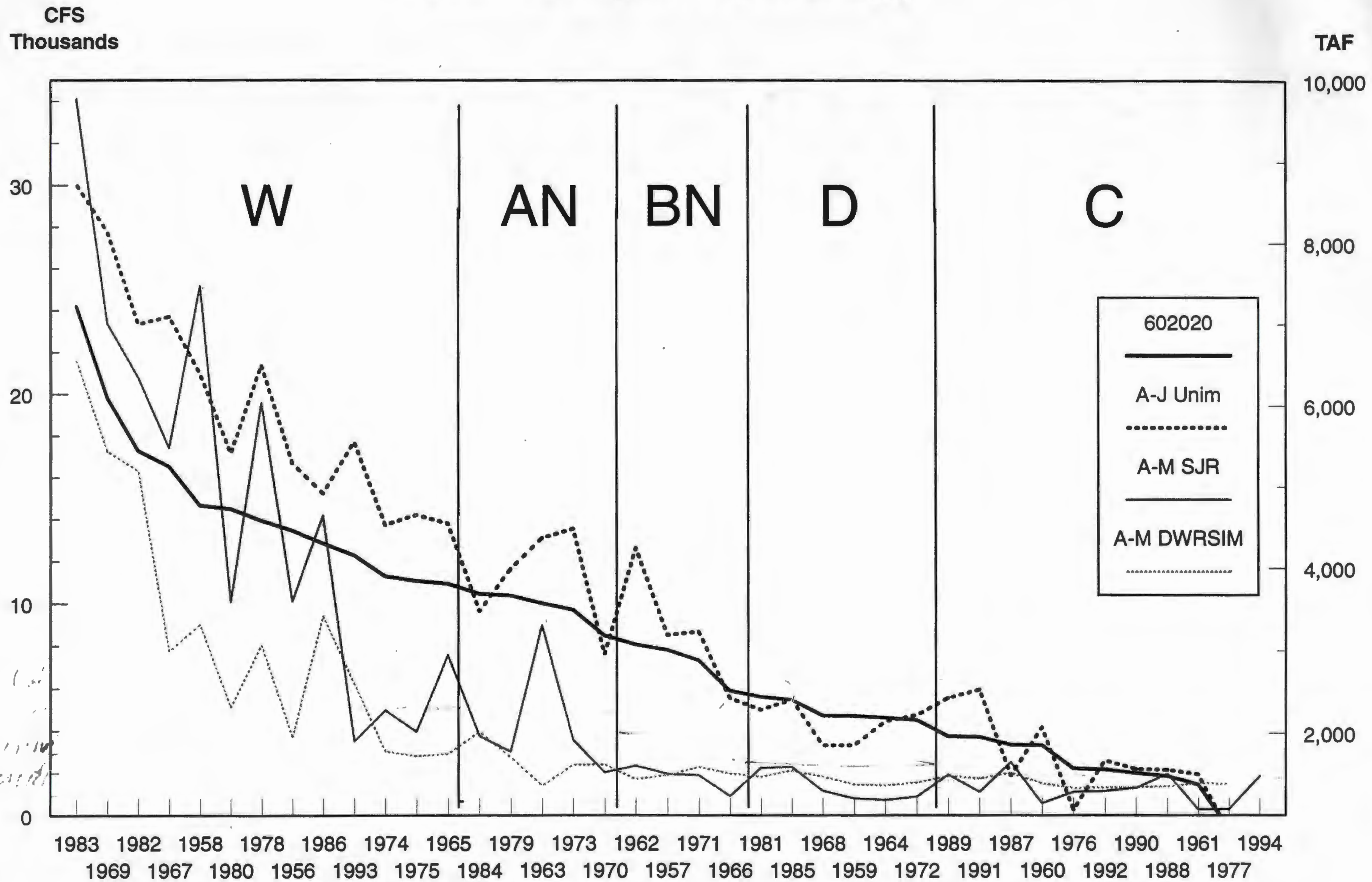

TABLE 3: San Joaquin Implementation Measures Compared

| Alternative | Max Total CVP/SWP Exports in cfs | Barrier Upper Old River | Vernalis Flow | Fall Run SSSI on San Joaquin |
|---|---|---|---|---|
| EPA | 4/15 to 5/15 1500<br><br>4/1 to 4/15 & 5/16 to 5/31<br><br>W[1] 6000<br>AN 5000<br>BN 4000<br>D 3000<br>C 2000 | 4/15 to 5/15 All Year Types | 4/15 to 5/15 Minimum CFS<br><br>W 10000<br>AN 8000<br>BN 6000<br>D 4000<br>C 4000<br><br>Other flows from 4/1 to 5/31 same as DWRSIM run used by USFWS for D-1630 | W .49<br>AN .35<br>BN .28<br>D .22<br>C .22<br><br>Avg = .33 |
| USFWS | 4/15 to 5/15<br><br>W 6000<br>AN 5000<br>BN 4000<br>D 3000<br>C 2000 | 4/1 to 5/31 All Year Types | 4/15 to 5/15 Minimum CFS<br><br>W 10000<br>AN 8000<br>BN 6000<br>D 4000<br>C 2000<br>Other flows from 4/1 to 5/31 same as DWRSIM run used by USFWS for D-1630 | W .49<br>AN .41<br>BN .40<br>D .35<br>C .32<br><br>Avg = .41 |

Somewhat lower than from

(CUWA) .25

.10

double

EPA
4x dry
.88 wet

CUWA
2x dry
~.45 wet

Kemmerer:
2x to 3x dry
.75 wet

[1]Many of the implementation measures in Table 3 vary by the water year category. Those categories are wet (W), above normal (AN), below normal (BN), dry (D) and critically dry (C).

From CUWA meetings

See Notes on End

This assumes $Q^W$ is (not) there

Not Final 10/04/94

per Dan Nelson

# The Technical Workgroup's Initial Ideas on Flow, Operational, and Category III Measures

"Category IV" = shelf life, integration of ESA

| FLOW & OP. MEASURES | SPRING, SUMMER, FALL, WINTER |
|---|---|
| Sacramento River Outflow | Flow Measures:<br>Sep. 1-30: Min. 3,000 cfs monthly average flow (-X% avg. daily flow fluctuations) at Rio Vista in all year types<br>Oct. 1-31: Min. 3,000/4,000/4,000/4,000/4,000 cfs monthly average flow (-X% avg. daily flow fluctuations) at Rio Vista in C/D/BN/AN/W year types<br>Nov. 1 - Dec. 31: Min. 3,500/4,500/4,500/4,500/4,500 cfs monthly average flow (-X% avg. daily flow fluctuations) at Rio Vista in C/D/BN/AN/W year types<br>Physical Measures: See near-term physical habitat and fish transport improvement measures under Category 3 attachment. |
| San Joaquin River Outflow<br><br>Less than NWRSIM Base Conditions<br><br>Typo | Flow Measures:<br>Feb. 15 - Apr. 14: Min. 1,000 cfs monthly avg. flow (-X% avg. daily flow fluctuations) at Vernalis in all year types<br>Apr. 15 - May 15: Min. 2,000/3,000/4,000/5,000/5,000 cfs monthly avg. flow (-X% avg. daily flow fluctuations) at Vernalis in C/D/BN/AN/W years; Pulse for 30 days<br>May 16 - May 30: Min. 1,000 cfs monthly avg. flow (-X% avg. daily flow fluctuations) at Vernalis in all year types<br>Oct. 1-31: Min. 1,000 cfs monthly average flow (-X% avg. daily flow fluctuations) at Vernalis in all year types<br>Oct. 1-31: Min. pulse/attraction flow of 28,000 acre-feet at Vernalis (no. of days to be determined based on real-time monitoring) during all-year types except no two critical years in a row; includes closure of Old River barrier.<br>Nov. 1 -Dec. 31: Min. 3,500/4,500/4,500/4,500/4,500 cfs monthly average flow (-X% avg. daily flow fluctuations) in C/D/BN/AN/W year types<br>Jan. 1 - 30: Min. 4,500 cfs if 8-river index ≤ 750,000 AF; or min. 6,000 cfs if 8-river index > 750,000 AF in all year types<br>Physical Measures: See near-term physical habitat & fish transport improvement measures under Category 3 attachment. |
| Net Delta Outflow<br><br>(a) Misses the 150 days at Confluence | Flow Measures:<br>Feb. 1 - Jun. 30: X2 standard with sliding scale & 3-way compliance measures (based on avg. daily salinity, 14-day avg., salinity, or equivalent flow at Confluence--7,100 cfs, Chipps Island--11,400 cfs, & Roe Island--29,200 cfs).<br>Apr. 1-30: Min. 30-days of X2 at Confluence (based on avg. daily salinity, 14-day avg., salinity, or equivalent flow at Confluence)<br>May 1-31: Min. 6,000 cfs monthly avg. flow (-X% avg. daily flow fluctuations) in all year types<br>Jun. 1-30: Min. 4,000 cfs monthly avg. flow (-X% avg. daily flow fluctuations) in all year types<br>May 1 - Jun. 30: 28-day average flow of 7,100 cfs if needed during dry & critical years based on real-time monitoring. (Modeled as a 28-day average flow starting on June 1; included in all years)<br>Jul. 1-31: Min. 4,000/5,000/6,500/8,000/8,000 cfs monthly average flow (-X% avg. daily flow fluctuations) in C/D/BN/AN/W year types<br>Aug. 1-31: Min. 3,000/3,500/4,000/4,000/4,000 cfs monthly average flow (-X% avg. daily flow fluctuations) in C/D/BN/AN/W year types<br>Sep. 1-30: Min. 3,000 cfs monthly average flow (-X% avg. daily flow fluctuations) in C/D/BN/AN/W year types<br>Oct. 1-31: Min. 3,000/4,000/4,000/4,000/4,000 cfs monthly average flow (-X% avg. daily flow fluctuations) in C/D/BN/AN/W year types<br>Nov. 1 -Dec. 31: Min. 3,500/4,500/4,500/4,500/4,500 cfs monthly average flow (-X% avg. daily flow fluctuations) in C/D/BN/AN/W year types<br>Jan. 1 - 30: Min. 4,500 cfs if 8-river index ≤ 750,000 AF; or min. 6,000 cfs if 8-river index > 750,000 AF in all year types<br>Physical Measures: See near-term physical habitat & fish transport improvement measures under Category 3 attachment. |
| Pulse Flow | During the Spring period, develop program to evaluate tidally adjusted pulses; During Fall period, see San Joaquin River flows |

Jan 1 — May 20 : Extend Xchannel closure with an acoustical barrier

| | |
|---|---|
| Export/Inflow Ratio Limits<br><br>How do these tie in?<br><br>Take issue — | (1) All year: Never limit pumping < 1,500 cfs in all year types<br>(2) Mar. 1 - Jun. 30: Limit pumping to ≤ 30% Delta inflow (35% if no significant adverse impact to fisheries);<br>Jul. 1-31: Limit pumping to ≤ 35% of Delta inflow (≤ 55% if no significant adverse impact to fisheries)<br>Aug. 1-31: Limit pumping to ≤ 55% of Delta inflow (≤ 65% if no significant adverse impact to fisheries)<br>Sep. 1-30: Limit pumping to ≤ 55% of Delta inflow (≤ 65% if no significant adverse impact to fisheries);<br>Oct. 1 - Feb. 28: Limit pumping to ≤ 65% of Delta inflow<br>100% San Joaquin River Flows<br>(3) Monitor at pumps & in-Delta:<br>If take ≤ X% density of population, then OK to pump at higher % inflow; or<br>If take > X% density of population, then maintain export/inflow ratios at lower % inflow;<br>(4) Mitigation incentives:<br>As an incentive to mitigate adverse impacts to fisheries, an agency would develop and implement physical habitat or fish transport improvement measures and receive a mitigation credit to increase export/inflow % ratios during a specified period of the year. |
| Direct Export Limits | Apr. 15 - May 15: Exports w/ Old River barrier = 100% of Vernalis flow |
| Permanent & Acoustic Barrier | Nov. 1 - Jun. 30: Install Georgiana Slough acoustic barrier; all year types.<br>Jan. 1 - May 20: Close X-channel in all year types until other appropriate fish exclusion barrier is installed. — Using acoustical?<br>Apr. 15 - May 15: Install barrier at head of Old River; base operation on real-time monitoring.<br>Sep. 15 - Dec. 31: Install barrier at head of Old River; base operation on real-time monitoring. |
| Salinity - Munic. & Industrial | All year: 155/165/175/190/240 days per year during C/D/BN/AN/W at CCWD or Antioch Water Works Intake on the San Joaquin River; provided in intervals of not less than two weeks in duration.<br>All year: Max. 250 mg/l maximum mean daily chloride at CCWD, City of Vallejo, Clifton Ct. Forebay, Tracy P. Plant |
| Salinity Delta Agriculture | Apr. 1 - Aug. 15:<br>Emmaton (Sac. River): Based on 14-day running average of mean daily EC<br>C: 2.78 mmhos EC (Apr. 1 - Aug. 15)<br>D: 0.45 mmhos EC (Apr. 1 - Jun. 15) 1.67 mmhos EC (Jun. 16 - Aug. 15)<br>BN: 0.45 mmhos EC (Apr. 1 - Jun. 20) 1.14 mmhos EC (Jun. 21 - Aug. 15)<br>AN: 0.45 mmhos EC (Apr. 1 - Jun. 30) 0.63 mmhos EC (Jul. 1 - Aug. 15)<br>W: 0.45 mmhos EC (Apr. 1 - Aug. 15)<br>Jersey Point (S.J. River): Based on 14-day running average of mean daily EC<br>C: 2.20 mmhos EC (Apr. 1 - Aug. 15)<br>D: 0.45 mmhos EC (Apr. 1 - Jun. 15) 1.35 mmhos EC (Jun. 16 - Aug. 15)<br>BN: 0.45 mmhos EC (Apr. 1 - Jun. 20) 0.74 mmhos EC (Jun. 21 - Aug. 15)<br>AN,W: 0.45 mmhos EC (Apr. 1 - Aug. 15)<br>Terminous (Mokelumne River): Based on 14-day running average of mean daily EC<br>C: 0.54 mmhos EC (Apr. 1 - Aug. 15)<br>D,BN,AN,W: 0.45 mmhos EC (Apr. 1 - Aug. 15)<br>San Andreas Landing (S.J. River): Based on 14-day running average of mean daily EC<br>C: 0.87 mmhos EC (Apr. 1 - Aug. 15)<br>D: 0.45 mmhos EC (Apr. 1 - Jun. 20) 0.58 mmhos EC (Jun. 21 - Aug. 15)<br>BN, AN, W: 0.45 mmhos EC (Apr. 1 - Aug. 15)<br>Apr. 1 - Aug. 30:<br>Max. 0.7 mmhos EC based on 14-day running average of mean daily at Vernalis, Old River near Middle River, Old River at Tracy Road Bridge, Brandt Bridge (WQCP-1991).<br>Sep. 1 - Mar. 31:<br>Max. 1.0 mmhos EC based on 14-day running average of mean daily at Vernalis, Old River near Middle River, Old River at Tracy Road Bridge, Brandt Bridge (WQCP-1991).<br>All Year:<br>Vernalis: Max. 500 mg/l TDS mean monthly average (WQCP-1991)<br>SWP/CVP Intakes: Max. 1.0 mmhos EC based on 14-day running average of mean daily (WQCP-1991) |

| | |
|---|---|
| Striped Bass Spawning<br><br>Same as WQCP? | Apr. 1 - May 31:<br>Prisoners Point (S.J. River): Max. 0.44 mmhos EC (based on average mean daily salinity) until spawning has ended; Relaxed to max. 0.55 mmhos EC when Antioch spawning criteria relaxed.<br>Apr. 15 - May 31:<br>Antioch (S.J. River): Max. 1.5 mmhos EC (based on 14-day running average of mean daily salinity) until spawning has ended. (Note: Criteria extended from May 5 to May 31 by WQCP-1991.)<br>Apr. 1 - May 31:<br>Antioch Relaxation Criteria: Replaces above Antioch & Chipps criteria whenever the projects impose deficiencies<br>Deficiency / Critical Year Criteria / Dry Year Criteria<br>0.0 MAF / 1.5 mmhos EC / 1.6 mmhos EC<br>0.5 MAF / 1.9 mmhos EC / 1.8 mmhos EC<br>1.0 MAF / 2.5 mmhos EC / 1.8 mmhos EC<br>1.5 MAF / 3.4 mmhos EC / 1.8 mmhos EC<br>2.0 MAF / 3.7 mmhos EC / 1.8 mmhos EC |
| Suisun Marsh (Preservation Agreement) | Oct. 1 - May 31:<br>Suisun Marsh Criteria: Monthly average of both daily high tides in mmhos EC at Collinsville, Montezuma Slough, Chadbourne Slough, Cordelia Slough, Suisun Slough, Goodyear Slough (Locations may differ):<br>Critical & Dry: Oct. 19.0, Nov. 15.5, Dec. 15.5, Jan. 12.5, Feb. 8.0, Mar. 8.0, Apr. 11.0, May 11.0<br>BN, AN, W: Oct. 19.0, Nov. 18.5, Dec. 15.5, Jan. 15.5, Feb. 15.5, Mar. 15.5, Apr. 14.0, May 12.5 |

# Category III -- Regulation of Bio-Degradation Factors and Near-Term Physical Habitat & Fish Transport Measures

Management of the following factors is an integral part of these recommendations. We are recommending specific management programs to address each of these factors.

1. Unsreened water diversions in the Sacramento River, Delta, and other locations;
2. Waste discharge control and pollution prevention (including pesticides);
3. Legal fishing (sport fishing and commercial harvest);
4. Illegal fishing (poaching control);
5. Land-derived salts;
6. Control of exotic species;
7. Restoration of riparian, wetland, and estuarine habitats; and
8. Control of channel alteration.

Factor 7, "Restoration of riparian, wetland, and estuarine habitats," has been expanded and should be given high priority. This factor has been renamed to and is now called the Habitat and Transport Improvement Program.

The purpose of this program is to define and implement a number of measures to improve habitat and to change transport so that migration patterns are protected and fish can move to desirable areas and avoid harmful ones.

The major features of the Habitat and Transport Improvement Program are:

1. It should be a formal program with a budget and both policy and technical direction;
2. It should be carried out either independently or under the auspices of the Federal-State Agreement;
3. Water users will participate actively;
4. This program will be linked with requirements constraining water project operations, and one purpose of the program will be the quantification of these linkages;
5. The program should be on a fast track schedule because of its importance.

Specific projects to be considered by the Habitat and Transport Improvement Program are described on the following list. These examples are in addition to projects already under consideration as part of the Four Pumps mitigation program.

1. Restoration of shallow-water and fish migration habitat Sutter Island and Sutter and Steamboat sloughs;
2. Restoration of shallow-water habitat at various locations including Sherman or Twitchell Island;
3. Restoration of riverine habitat (levee set-back, river deepening, and riparian enhancement) one major salmon migration route in the Central Valley;
4. Installation and testing of acoustic barriers at Turner Cut, the North Fork of the Mokelumne River, and other selected locations;

# Impact of Bay-Delta Water Quality Standards on California's Electric Utility Costs

**Prepared for**
**the Association of California Water Agencies**

**by**
**Richard McCann, M.Cubed**
**David Mitchell, M.Cubed**
**Dr. Lon House**

Final Report
October 7, 1994

Sacramento, California

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## 1.0 Summary and Conclusions

To date, economic impact analyses of alternative water quality standards for the San Francisco Bay/Sacramento-San Joaquin Delta (Bay-Delta) Estuary have not adequately addressed the potential impacts on California's electricity system. The purpose of this study is to evaluate the following issues:

- How will alternative standards affect operations of California's hydroelectric system, in particular that of the Central Valley Project?
- How will changes in hydro generation affect the production and dispatch of non-hydro generated power?
- How will alternative standards affect Central Valley Project and State Water Project pumping in the Delta and their related demands for electricity?
- How will alternative standards affect agricultural groundwater pumping and its related demand for electricity?
- What changes in air pollution emissions will result from changes in hydropower availability and load patterns?
- What are the economic costs (or benefits) associated with the above-listed adjustments?

A standardized set of power production and demand models were used to assess the impacts on these various aspects of the electric utility system. Hydrological simulation models of the CVP and SWP were used to determine changes in hydropower output and project pumping loads on those systems. Changes in hydropower generation in the Pacific Gas and Electric Co. (PG&E) system were estimated with a linear programming model. Changes in agricultural groundwater pumping were derived from analysis of historic loads and results from an agricultural production model. These impacts were input as changes in hydro generation and demand to the Elfin production-cost model of the Northern California planning area electricity system to determine changes in system costs and air emissions.

A set of *policy alternatives* were evaluated based on a memorandum from the State Water Resources Control Board (Board) staff to the Department of Water Resources (DWR) detailing the specific water quality and flow conditions.[1][1] Identified were two base cases that represent existing regulatory conditions before and after the issuance of two National Marine Fisheries Service (NMFS) biological opinions, and six policy alternatives proposed by various parties.[2] Three of the policy alternatives were evaluated against the first base case under three *water-year scenarios* that represent median, dry and wet water-year conditions. The results presented are for the weighted averages of these scenarios for the specified alternatives.

### 1.1 Summary of Results

Table 1 shows the relative costs for each alternative proposal evaluated against the D.1485 conditions base case, with costs both in total and per acre-foot of reduced water supply. Total costs range between $41 and $46 million per year. Emissions for several criteria air pollutants increase, which may trigger regulatory actions by local air districts.

**Table 1**
**Comparison of Alternative Policy Proposals to the State Water Resources Control Board**

| Cases[1] | Annualized Cost[2] (vs. Base Case #1: D.1485) | NPV Cost 1995-2010 (vs. Base Case #1: D.1485) | Annualized Cost Per AF[3] (vs. Base Case #1: D.1485) | NPV Cost per AF[3] (vs. Base Case #1: D.1485) |
|---|---|---|---|---|
| Alternative #1: EPA | $41.1 Million | $365 Million | $84 | $744 |
| Alternative #2: Board Staff | $46.4 Million | $412 Million | $72 | $638 |
| Alternative #3: CUWA | $46.4 Million | $412 Million | $82 | $723 |

Notes:
1 Each Base Case and Alternative represents a weighted-average cost for three scenarios: Median (50%), Dry (20%) and Wet (75%) water-year conditions.
2 Levelized annual costs over 1995-2010 planning horizon.
3 Cost per acre-foot of "71-Year Average Water Supply Impacts" from DWR, 9/1/94.

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[1] This memo is contained in Appendix A.

[2] The second base case specified in the memo--D.1485 plus NMFS biological opinion conditions--could not be modelled with the existing hydrological models due to the nature of species take limits at the project pumps. Also, the conditions specified in the fourth and sixth alternatives created insurmountable modelling problems based on the assumptions in the DWRSIM and PROSIM hydrological models.

## 1.2 Findings and Recommendations

The principal findings and recommendations in this report are as follows:

(1) Previous analyses of the impacts from Bay-Delta environmental protections (e.g., the winter-run salmon critical habitat designation) incorrectly concluded that the state's electricity system benefits from more strict standards. The results presented here demonstrate that past and proposed standards impose costs--not benefits--on the electric utility system.

(2) The cost impacts on the utility system are real and significant. Net present value costs of some alternatives approach one-half billion dollars. Their size indicates that they should be included in any analysis used in balancing the merits and detractions of a proposed standard.

(3) The cost impacts are not spread uniformly among the state's citizens, and these impacts can not be translated into a single rate change for all utility customers. Direct impacts on hydropower generation are concentrated among CVP project customers;[3] increased water pumping costs are concentrated among the San Joaquin Valley's agricultural sector.

(4) This analysis relies on several assumptions that may prove inaccurate. If these assumptions fail to be true, costs to the electricity system are likely to be significantly greater than reported here. First, annual reductions in water supply deliveries were assumed to be translated directly into increased groundwater pumping. However, based on analysis of the impacts from the NMFS opinions, other factors including how deliveries are shifted through the year and how the uncertainty of supply increases appear to magnify the effect of regulatorily-reduced supplies on groundwater pumping loads. Second, hydropower generation on the Merced and Tuolumne Rivers was assumed not to change. Though unrealistic, this assumption was necessary because of the high degree of uncertainty over how standards at Vernalis will be met. Third, any further restrictions on PG&E's fossil-fueled plants located on Suisun Bay have not been included. Use of these assumptions tend toward underestimating the cost impacts associated with the various alternatives.

(5) Initial hydrological analyses show that releases from New Melones Reservoir alone will not be able to meet the proposed standards on the San Joaquin River; large releases from other local projects (e.g., Merced Irrigation District's Exchequer, Merced and Turlock

[3]Western Area Power Administration (Western) customers may see costs fall due to the interaction between seasonal shifts in CVP capacity and institutional and contractual constraints within the Northern California power industry that lead to decreased capacity purchases by Western while regional capacity requirements increase. Western explains this situation further in its report prepared for the Board staff.

Irrigation Districts' New Don Pedro, San Francisco's Hetch Hetchy) also will be necessary. However, no economic analyses done to date have adequately addressed the costs imposed on these districts' customers. In addition, how these additional water releases are used after they enter the Delta has not been addressed; a significant potential exists for litigation among the various parties on this matter.

(6) Many other environmental mitigation planning processes (e.g., Trinity River restoration, San Joaquin River Management Program, Central Valley Project Improvement Act, Endangered Species Act reviews) are currently under way. The outcomes from these processes will influence both baseline conditions and the ability of the State Water Resources Control Board to establish consistent water quality standards. If these processes lead to *additive* rather than *concurrent* requirements, the cost impacts would be significantly greater than reported here.

(7) The high degree of uncertainty about both the scientific basis and likely resolutions of so many issues points to the need for an *adaptive management* approach to Bay-Delta water quality issues. The establishment of a fixed set of long-term standards is unrealistic under these conditions. The Board is the only agency with the authority to assess the cumulative impacts of these issues on the Bay-Delta and the affected economic interests. The Board should ensure that it has the flexibility to adjust standards as the economic penalties associated with the standards arise. The Board should establish a procedure to update the standards as new information and events warrant action.

## 2.0 How Electricity and Water Are Interconnected

California's electricity system is composed of a wide number of resources and is highly integrated. The Bay-Delta standards affect two aspects of this system in particular: hydropower generation and water pumping loads. To understand these effects, we first discuss the characteristics of the electricity system and the key economic components.

The demand, or the sum of hourly electrical requirements placed by customers on an electric utility, varies daily and throughout the year in predictable patterns. Figure 1 shows how hourly demand changes through the day. Winter demands in California are considerably lower than summer demands due to prevalence of air conditioning and reliance on natural gas for winter space heating. Daily demands peak in the afternoon or evening as people return from work, cool or heat their house and begin cooking and laundry. Due to the considerable changes in demand throughout the day, utilities rely on varying types of resources through the course of a day.[4]

Two key concepts are necessary to determine the economic value of the resources being used to meet these demand patterns. The first is *capacity*. Capacity is the amount of resources necessary to reliably meet demand at any given moment. That means that the required level of capacity equals the highest expected demand in a year plus a margin for error and possible outages. If, for example, the capability of a hydro resource is reduced as a result of lowered reservoir elevations (i.e., less storage), that resource's instantaneous ability to generate power will be decreased. When the capacity of a resource is reduced, the utility must either purchase or build replacement capacity. The annualized cost of electrical capacity usually is expressed in terms of dollars per kilowatt-year ($/kw-year).[5] As might be expected, the value of capacity is highest during summer afternoons and lowest during winter nights.

The second concept is *energy*. Energy is the total power consumption over a period of time. It equals the sum of all hourly loads over the entire time period (e.g., a year.) The cost of energy is typically measured in dollars or mills (tenths of a cent) per kilowatt-hour ($/KWh). The cost of providing energy typically varies through the day and the year; the lowest cost resources, called *baseload*, are used first and meet the lowest loads during *off-peak* periods. Figure 2 shows how these costs vary through the day and between seasons. As the loads increase, higher cost resources are added. On the Pacific Gas and Electric Co. system, incremental energy costs are often higher during the winter because natural gas prices rise during this season and maintenance

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[4]Summer demands on the Pacific Gas and Electric system may swing as much as 6,000 megawatts from the nighttime low to afternoon peak. For a perspective, the Diablo Canyon 1 nuclear generating station is capable of producing 1,073 megawatts.

[5]The California Public Utilities Commission determines the value for capacity for payments to third-party Qualifying Facilities (QFs) in the annual Energy Cost Adjustment Clause hearings for each utility.

Figure 1

**Typical PG&E Daily Load Profile**

***Summer and Winter Peak Days***

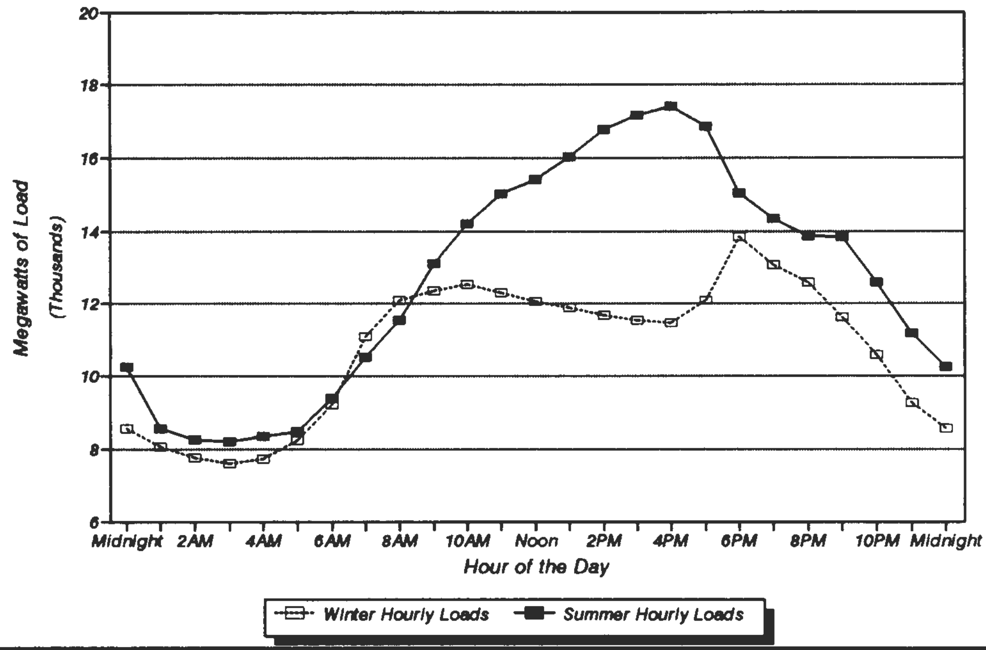
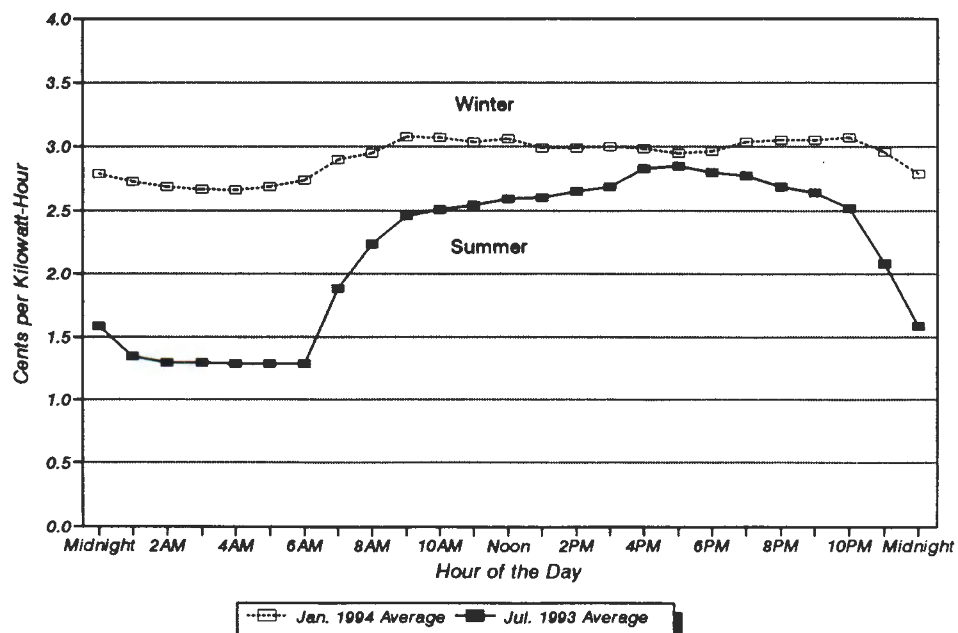



Figure 2

**PG&E Recorded Incremental Energy Costs**

***Summer and Winter Periods***



of the most efficient thermal plants is often scheduled then.[6] However, the daily swings in incremental energy costs are higher during the summer, varying as much as 50 percent.

Hydropower is an exception to the rule that low-cost resources are run constantly because it is reserved to meet *peak* demands due to limited energy availability. Hydropower is particularly valuable because it can readily and costlessly be turned on and off to match daily load swings--utilities employ it to meet the highest loads at low cost. Also, hydropower is used to displace fossil-fuel generation in urban areas during the hottest part of the day, thus decreasing air pollution emissions.

California has one of the largest hydroelectric power generation systems in the world, providing nearly one-fifth of the state's total generating capacity. The system produces "clean" energy and provides inexpensive peak power production. The total value of the state's hydropower production, as measured by the type of power it replaces (e.g. fossil fuels) exceeds $1.3 billion in a typical year.

The electric utilities in California currently seek to optimize the use of their available hydroelectric generation given existing operational constraints. If operational constraints change (e.g., different water release patterns) then the rest of the utility system will have to adjust to accommodate these new constraints. If the water available for release during a given period (e.g., a month) is reduced, then the production of energy is similarly reduced. This reduction of available energy, coupled with lower reservoir elevations, limits the ability of the hydroplant to meet peak loads on a sustained or recurring basis. In order to be in a position to meet recurring peak loads throughout a month, the available energy must be conserved by decreasing the amount of peak load met by the facility in any one hour. This in turn forces a reduction in the hydroplant's firm load-carrying capability. Given past experience, shifts in hydroelectric generation from summer peak periods to "around the clock" or baseload type of operation will tend to increase utility operating costs and to accelerate the acquisition of additional peaking resources.

A full economic analysis requires that the costs of both capacity and energy be considered. In the case of the water quality standards for the Bay-Delta, capacity will be affected by changes in hydropower capability and timing of pumping loads; energy will be impacted by timing and amount of reservoir releases, and changes in total amounts of water delivery and use that affect pumping loads. Standards will directly impact loads and power production along the Central Valley Project (CVP) and State Water Project (SWP) systems. Other hydropower plants may change their storage and release patterns as well, especially if flood control constraints change or requirements to provide flow relief in the Delta extend beyond the CVP and SWP. Additional groundwater pumping may increase system demands, particularly during peak summer months.

[6]The incremental energy costs are operating costs of the last generating resource dispatched on the utility system. This generation resource is the one that will increase generation in response to increased electrical demands, or decrease generation as demands fall.

At the same time, inexpensive surplus power from the Pacific Northwest is expected to decline due to fishery recovery efforts in that region, putting an additional premium on in-state hydro generation. Less peaking hydropower from the CVP and the SWP and increased load from groundwater pumping could require additional generation from more expensive and air-polluting natural-gas-fired plants in urban regions, particularly in dry and critically dry years.

## 3.0 Analytic Methodology

The overall approach was to use hydrological simulation models in concert with an electric utility production-cost model to determine the impacts of changes in water release patterns on electrical generation. This is a fairly traditional approach and one that the Board is familiar with. In particular, the Lower Yuba River hearings conducted in 1992 spent considerable time reviewing the same methodology as is used here.[2]

The analysis required modelling the following energy and water resources:[7]

- Central Valley Project (CVP);
- State Water Project (SWP);
- Pacific Gas & Electric Co. (PG&E) hydropower system;
- Hydropower projects operated in conjunction with irrigation and water district supply systems in Northern California;
- Hydro plants owned by various municipal utilities, e.g. the Sacramento Municipal Utility District's (SMUD) Upper American River Project;
- Non-utility-owned "qualifying facilities" (or QFs); and
- Power interties between California and the Pacific Northwest.

In addition, agricultural energy demand associated with groundwater pumping was modeled.

The method used to determine the impact of proposed shifts in hydroelectric generation is to conduct a utility simulation using what is called a utility production-cost model. These utility simulation models take as inputs the hourly demand forecast, generating resource characteristics (including emissions), cost and availability, and utility system operating constraints (such as reserve requirements). The model then determines the commitment and dispatch of the utility generation resources to meet system demands. A base case, assuming current operating conditions, is simulated first. Then alternative cases, using different hydro release and pumping load patterns, are simulated, and the total cost and emissions from these alternatives are compared to the base case values to determine cost and pollution impacts of the alternatives.

Several key assumptions drive much of the results from these studies. First, we assumed that annual reductions in water supply deliveries can be translated directly into increased groundwater pumping. However, based on analysis of the impacts from the NMFS opinions, other factors

[7] A description of these systems is provided in Appendix B.

including how deliveries are shifted through the year and how the uncertainty of supply increases appear to magnify the effect of regulatorily-reduced supplies on groundwater pumping loads. For this reason, the increase in groundwater pumping could be significantly underestimated in this analysis.[8]

Second, we have excluded the changes in hydropower generation on the Merced and Tuolumne Rivers because of the uncertainty in where the additional flows required for meeting Vernalis standards will come from. With additional April and May release requirements of up to 600,000 acre-feet, significant economic costs will be incurred yet these have no been identified, much less estimated, in other analyses presented to EPA or the Board.[9]

Third, any further restrictions on PG&E's fossil-fueled plants located on Suisun Bay have not been included. PG&E currently restricts operations in May and June to reduce striped-bass losses. Meeting other species survival goals would lead to higher operational costs.[10]

### 3.1 Analytic Models

The following analytic resources were used to model the above systems:

**DWRSIM** was used to calculate water deliveries, power production and pumping load for the State Water Project. DWRSIM output was provided by the Department of Water Resources, and is the same as that provided to the Board and the U.S. Environmental Protection Agency (EPA) for their economic impact assessments of alternative standards.

**PROSIM** was used to calculate water deliveries, power production and pumping load for the Central Valley Project. PROSIM output was provided by Water Resources Management, Inc. (WRMI), and is calibrated to be consistent with the DWRSIM output.[11]

**PG&EHELP**, a linear programming simulation model of PG&E's hydroelectric resources, was developed to analyze impacts to the PG&E system. This model was developed so that sharing arrangements to meet alternative standards that include other projects in addition to the SWP and

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[8]See Appendix D for a discussion of the groundwater pumping estimates.

[9]See Appendix H for a discussion of the flow requirements on the San Joaquin River.

[10]See Appendix E for a discussion of existing and potential limitations on PG&E's thermal plants located in the Bay-Delta Estuary.

[11]Both DWRSIM and PROSIM are described in more detail in Appendix C.

CVP could be analyzed.[12] When standards are met entirely by the CVP and SWP, the PG&E system is not directly affected.[13]

**CVPM** was used to analyze changes in groundwater pumping load. This model is being used to evaluate the impacts on agriculture of the proposed EPA standards and the Central Valley Project Improvement Act (CVPIA). As discussed below, this data was supplemented with an analysis of groundwater pumping loads based on historic water deliveries and agricultural energy demands to provide more robust estimates of groundwater pumping response.[14]

**ELFIN**, a production-cost model of the Pacific Gas & Electric power system, was used to calculate the net cost or benefit associated with the above adjustments in terms of energy production, generation capacity and air pollutant emission levels.[15] The changes in hydropower generation, the increased agricultural pumping demand, and decreased project pumping are incorporated into the model.[16] Elfin then solves for how use of other resources (e.g., natural gas, coal, renewables) would change. Elfin is the planning model used by the state's energy regulatory agencies--the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC).

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[12]On the San Joaquin River, the proposed alternatives may significantly affect flows on the Merced and Tuolumne Rivers, which are controlled by local irrigation district projects. However, the information provided by the DWRSIM and PROSIM output is insufficient to model the impacts on the projects on these two rivers without explicit policy decisions being made about allocation of release burdens. A further discussion is contained in Appendix H.

[13]Details of the PG&EHELP model are provided in Appendix C.

[14]Details of the groundwater pumping analysis are provided in Appendix D.

[15]Elfin is developed and licensed by the Environmental Defense Fund. Details about this model and basic input assumptions are provided in Appendix C. In addition, Western used the PROSYM production-cost model to evaluate its system. These results were used to determine capacity changes on the CVP. PROSYM is not discussed in Appendix C.

[16]Changes in current Bay-Delta standards may impact several of PG&E's fossil-fueled thermal generating plants. While these impacts are ignored in this analysis, a further discussion of this issue is included in Appendix E.

### 3.2 Evaluating Water Quality Standard Alternatives in Water-Year Scenarios

Hydroelectric power impacts associated with the water quality alternatives proposed by the Board staff in its August 18, 1994 memo to the DWR were estimated.[1] These alternatives are summarized below:[17]

**Alternative 1**: Proposed by EPA. Relative to conditions under State Water Resources Control Board Decision 1485 (D-1485), annual SWP and CVP deliveries would be reduced by 1.09 million acre-feet in critically dry years and by 0.49 million acre-feet in average years. Average annual carryover storage would be reduced by 0.17 million acre-feet in the Sacramento Basin and by 0.73 million acre-feet in New Melones Reservoir.

**Alternative 2**: Proposed by the Board staff. Relative to D-1485, annual SWP and CVP deliveries would be reduced by 1.56 million acre-feet in critically dry years and by 0.65 million acre-feet in average years. Average annual carryover storage would be reduced by 0.20 million acre-feet in the Sacramento Basin and by 0.67 million acre-feet in New Melones Reservoir.

**Alternative 3**: Proposed by California Urban Water Agencies. Relative to D-1485, annual SWP and CVP deliveries would be reduced by 1.39 million acre-feet in critically dry years and by 0.57 million acre-feet in average years. Average annual carryover storage would be reduced by 0.25 million acre-feet in the Sacramento Basin and by 0.67 million acre-feet in New Melones Reservoir.

**Alternative 4**: Proposed by the California Department of Fish and Game. Relative to D-1485, annual SWP and CVP deliveries would be reduced by 2.6 million acre-feet in critically dry years and by [not specified by DWR] in average years. Average annual carryover storage would be reduced by [not specified by DWR] million acre-feet in the Sacramento Basin and by [not specified by DWR] million acre-feet in New Melones Reservoir.[18]

**Alternative 5**: Proposed by David Schuster and Chuck Hansen. Relative to D-1485, annual SWP and CVP deliveries would be reduced by 0.80 million acre-feet in critically dry years and by 0.21 million acre-feet in average years. Average annual carryover storage would be reduced by 0.33 million acre-feet in the Sacramento Basin and by 0.63 million acre-feet in New Melones Reservoir. This alternative is currently being reformulated as Alternative 8.

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[17]This summary is based on preliminary results provided by DWR at the September 1, 1994 Board Workshop. Descriptions of these alternatives and preliminary hydrological results from DWRSIM for each alternative is provided in Appendix A.

[18]Initially, the DWRSIM model could not meet the flow requirements in all years for this proposal. The standards were reformulated for the model, but the results were not yet available as this report went to press.

**Alternative 6**: Proposed by Jones and Stokes. Relative to D-1485, annual SWP and CVP deliveries would be reduced by 1.81 million acre-feet in critically dry years and by 0.99 million acre-feet in average years. Average annual carryover storage would be increased by 0.48 million acre-feet in the Sacramento Basin and reduced by 0.41 million acre-feet in New Melones Reservoir.[19]

This is the base case used for the presentation in this report. The analysis herein estimates the impacts for Alternatives 1 through 3 only. Alternatives 4 and 6 could not be modelled with the current versions of either DWRSIM or PROSIM, and Alternative 5 is currently being revised by its sponsors. Impacts for each alternative were estimated relative to the primary base case specified in the Board staff's memo, which is project operations under D-1485. The first base case is used to estimate the cumulative impacts of regulatory actions in the Delta to date.

A second base case proposed in the Board staff memo would evaluate project operations under D-1485 and the NMFS biological opinions. However, the difficulty of modelling the endangered species take limits at the project pumps, which have a significant impact on the projects operations, delayed completion of this analysis.[20] This base case, which has been adopted by EPA for its analysis, would be used to estimate the incremental cost associated with each water quality alternative. The results for this base case were not available at the time this report was concluded, but could be incorporated into future analyses.

A third base case which would be appropriate are the conditions under the Central Valley Project Improvement Act. This would include the 800,000 acre-foot environmental set-aside and the goal of doubling anadromous fish populations. However, the requirements and timing of the conditions specified in the CVPIA are not sufficiently detailed at this time to adequately model this case. Nevertheless, the Board may wish to consider whether the CVPIA will be additive or inclusive of the proposed EPA and state Bay-Delta standards, and whether the proposed state standards can be melded to meet the CVPIA goals.

For each policy alternative, impacts were estimated for dry, median, and wet year conditions to determine the sensitivity of the results to hydrologic conditions and to provide a probability distribution of water years to calculate average annual impacts.[21]

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[19]The PROSIM model could not meet the proposed flow requirements for all years in this alternative.

[20]DWR recently provided EPA with DWRSIM results that do not incorporate the effects of take limits.

[21]The median year conditions equal the average of the seven years centered on the 50th percentile water year; for dry years, it equals the average of the seven years centered on the 20th percentile year; for wet years, it equals the average of the seven years centered on the 75th percentile year. These years correspond to those used by PG&E in specifying median, dry and wet conditions for planning purposes. Results from the hydrological models, PROSIM and

## 4.0 Results

The alternatives are compared based on the aggregate costs of energy, capacity and air emissions. The energy costs for each alternative were estimated based on the weighted-average energy impacts from the three water-year scenarios over the 1995 to 2010 time horizon.[22] Added capacity needs and costs were based on:

(1) the estimate made by the Western Area Power Administration (Western) to meet obligations to Western's customers of the CVP under critically-dry water conditions;[23] and

(2) the added capacity needs imposed in dry years from increased agricultural pumping in the PG&E service area; these capacity costs are based on the current short-run capacity payments to QFs, escalated into the future.[24]

The emission costs are derived from values adopted by the CEC in its ***1994 Electricity Report***.[3; 4]

It is important to note that the hydrological models are not adequate for capturing the full effects of the daily flow requirements that determine the ability of hydro facilities to match daily load swings. How project pumping might be shifted through the year also will affect groundwater pumping levels. For example, the NMFS opinions appear to have created a large increase in agricultural pumping with relatively small decreases but significant shifts in water project deliveries. Estimates of groundwater pumping impacts need to be further refined as well with more detailed data. While the groundwater issue has been largely ignored by previous analyses, it may represent the largest single cost item to agriculture.

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DWRSIM, were either taken directly from these year types or adjusted linearly to estimate changes in hydropower generation and groundwater pumping loads. The probability weights attached to each water year were 0.20 for dry years, 0.55 for median years and 0.25 for wet years.

[22]Assuming a 7 percent real discount rate per the U.S. Office of Management and Budget. (U.S. Office of Management and Budget, "Benefit-Cost Analysis of Federal Programs: Guidelines and Discount Rates," Circular A94, in Federal Register 53(519), November 19, 1992.)

[23]These estimates will be presented in testimony submitted to the Board by Western and its consultants.

[24]Because the analysis presented here focuses on long-term impacts, a long-run capacity value may be more appropriate. The results from the recent Biennial Resource Plan Update bids accepted by the CPUC might be used, but these offers have been withdrawn with the recent deregulation proposals offered by the CPUC. The short-run values presented here are relatively consistent with the long-term offers and are non-controversial. A fossil-fueled combustion turbine is used as the capacity proxy.

### 4.1 Cost Impacts

Table 1 in the Summary and Conclusion above summarizes the annual and net present value impacts of each alternative for the weighted average.[25] The first case assessed is *Alternative 1* (proposed EPA standards) relative to conditions existing under D-1485. The net energy generation from the CVP increases by an average of 170 GWH as project pumping loads fall faster than hydropower losses. However, the shifting of available energy from the summer and spring, as illustrated in Figure 3, and the loss of hydropower capacity--up to 116 MW on the CVP alone under dry summer conditions--makes this energy less valuable to the system. Also agricultural pumping loads increase an average of 533 GWH in annual energy and 134 MW in peak demands, leading to a net decrease of available energy of 363 GWH. The net present value impact over the 1995 to 2010 time horizon is $365 million, equivalent to an annualized value of $41.1 million. Based on the average reductions in water supply estimated by the DWR staff, these costs are equivalent to about $745 net present value per acre-foot or $84 per acre-foot per year.

annualized?

*Alternatives 2 and 3* have similar impacts, which was expected given the similarity in their parameters on water flows and quality measures. (See [5] for details.) Alternative 2 incurs a net present value cost of $412 million over the 1995-2010 horizon or $46.4 million per year. Alternative 3 incurs a net present value cost of $412 million over the 1995-2010 horizon or $46.4 million per year. The costs per acre-foot diverge due to the larger impacts on the water supply for Alternative 2. For Alternative 2, the net present value cost is $638 per acre-foot or $72 per year. For Alternative 3, the net present value cost is $723 per acre-foot, equal to $82 per year.

In the base case under D-1485, the expected operational costs for the PG&E control area in 1995 is $3.472 billion. The operational cost increase attributable to a dry-water year is $170 million above the median case. Thus, the cost impacts from the various policy proposals are about one-quarter of the magnitude incurred during a drought.

We must offer one point of caution in interpreting these results: *these changes in costs will not be shared equally among all Northern California ratepayers*. The loss of summertime hydropower capacity and energy will be borne by the municipal utilities (e.g., SMUD, NCPA) that purchase their lowest cost power from Western. These changes will be spread over a ratepayer base less than one-eighth of PG&E's. Most of the costs associated with increased agricultural pumping will be incurred by agricultural energy customers. This group represents only 4 percent of PG&E's annual load. Costs of increased air pollution will be borne mostly by local residents located near PG&E's natural-gas fired power plants, (e.g., Pittsburg, Antioch, Moss Landing, Morro Bay, and Hunters Point). For these reasons, the costs simply can not be divided by PG&E's revenue requirements and translated into a system-wide rate increase.

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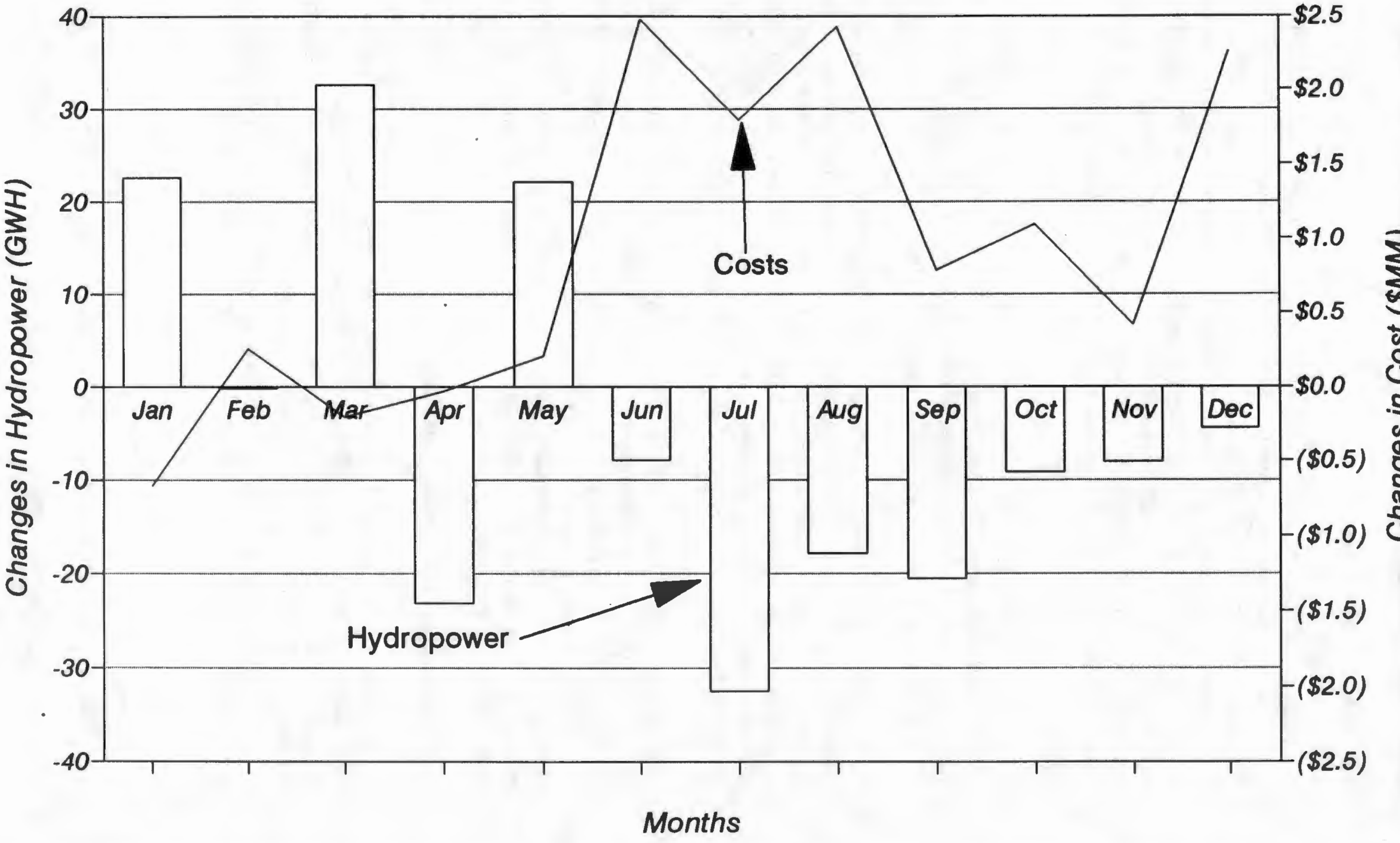
[25] Appendix F contains the tables detailing the annual cost and emission impacts for each alternative based on the Elfin results.

## Figure 3

# Hydropower and Cost Impacts by Month

***1995 Example for Alternative 1***



### 4.2 Air Pollution Impacts

Air pollution is a serious problem in California. Of the fourteen air basins in California, ten have been designated as non-attainment areas for ozone, and only one out of the 58 counties has met the standards for airborne particulate matter. The generation of electricity by fossil fuels produces a host of emissions that contribute to California's air pollution problems. Recognizing this impact, the evaluation of air quality impacts of energy resource options is mandatory in the State of California.[6] For this analysis, we are concerned about the following commonly measured emissions: oxides of nitrogen (NOx), particulate matter of less than 10 microns in diameter (PM10) and reactive organic gases (ROG), carbon emissions (Cx), and oxides of sulfur (SOx).

In some cases, emissions can be estimated simply from the amount of fuel burned by a generator. However in most cases, the emissions are a function of operating level of each plant and how the efficiency of that plant changes as the level changes. Using a production costs model such as Elfin is the best way to estimate emissions in these cases.

In *Alternative 1*, the average annual emissions increase by 131 tons of NOx, 53 tons of SOx, 9 tons of PM10, 6 tons of ROG and 60,000 tons of carbon.[26] The annualized costs based on CEC-adopted values is $3.1 million per year. While these values are not large relative to emissions inventories in the impacted air basins, these emission increases are large enough to trigger new source review (NSR) requirements that may create a need for PG&E to purchase emission reduction credits (ERCs) or reduce the amount available in community banks.[7]

*Alternatives 2 and 3* again have similar impacts on air pollution emissions. In Alternative 2, the average annual emissions increase by 144 tons of NOx, 68 tons of SOx, 9.5 tons of PM10, 7 tons of ROG and 56,000 tons of carbon. In Alternative 3, the average annual emissions increase by 149 tons of NOx, 75 tons of SOx, 9 tons of PM10, 5.5 tons of ROG and 56,000 tons of carbon. As with Alternative 1, the emission levels vary widely from year-to-year depending on scheduled maintenance of various thermal-powered units (e.g., Diablo Canyon), and they tend to increase over time as system loads increase.

### 4.3 Comparison with Previous Studies

A previous analysis reported net benefits to hydropower due to operational changes to comply with the winter-run chinook salmon critical habitat designation by the National Marine Fisheries Service.[8] The winter-run salmon report found a net benefit to the electricity generation system of $48.9 million per year. The results of our analysis contradicts this earlier finding suggesting that operational changes with the CHD and other Bay-Delta standards will result in a net cost to the system. However, the results in the winter-run salmon study were driven by misapplication

[26]The annual emission increases for each alternative are shown in Appendix F.

of electricity planning concepts.[27] The benefits derived relied on increased availability of capacity in wet winter months rather than dry summer months, higher generation in two out of 55 water years that skewed the water history average, and failing to account properly for increased groundwater pumping in the San Joaquin Valley. In reality, the winter-run salmon CHD has resulted in significant costs. Measured losses to CVP hydropower generation alone have totaled $44 million net present value over the last six years.[9] Cost of meeting increased groundwater pumping loads amount to about $116 million over the same period. As a result, agricultural customers may have seen an additional $50 million annual increase in their energy bills.[28] Instead of net benefits, the total estimated cost to the California electricity system since 1989 has been about $160 million net present value.

[27]A more detailed critique of the Hydrosphere report is contained in Appendix G.

[28]See Appendix D for a discussion of groundwater pumping impacts.

## Appendix A

## Description of Base and Alternative Cases

The alternative cases analyzed in this report are based on results from analyses done be DWR at the request of the Board staff. Attached are:

(1) The memorandum from Tom Howard of the Board staff to George Barnes of DWR specifying the flow conditions for each case, and

(2) A summary table issued by DWR on September 1, 1994 showing the aggregate changes produced from DWRSIM for each alternative case.

STATE OF CALIFORNIA - CALIFORNIA ENVIRONMENTAL PROTECTION AGENCY

PETE WILSON, *Governor*

**STATE WATER RESOURCES CONTROL BOARD**

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**DIVISION OF WATER RIGHTS**
P.O. BOX 2000, Sacramento, CA 95812-2000

AUGUST 18 1994

To Whom It May Concern:

ALTERNATIVE STANDARDS FOR THE BAY-DELTA ESTUARY

The enclosed memorandum has been sent to the Department of Water Resources to request its assistance in estimating the water supply impacts of alternative standards for the Bay-Delta Estuary. The memorandum is being distributed for informational purposes.

The alternatives identified in the memorandum are preliminary and may change as the process proceeds. The subject of alternative standards for the Bay-Delta Estuary will be discussed at a workshop scheduled for September 1-2, 1994. Workshop notices were mailed under separate cover.

If you have any questions, please contact me at (916) 657-1873.

Sincerely,

Thomas Howard

Thomas Howard, Chief
Bay-Delta Unit

State of California

# Memorandum

To : George Barnes, Chief
Modeling Support Branch
Department of Water Resources
1416 Ninth Street
Sacramento, CA 95814

Date: AUGUST 18 1994

Thomas Howard

From : Thomas Howard, Chief
Bay-Delta Unit
STATE WATER RESOURCES CONTROL BOARD
901 P Street Sacramento, CA 95814
Mail Code G-8

Subject: REQUEST FOR DWRSIM OPERATION STUDIES

The purpose of this memorandum is to request the Department of Water Resources' (DWR) assistance in estimating the water supply impacts of alternative standards for the Bay-Delta Estuary.

The State Water Resources Control Board (SWRCB) is undertaking a triennial review of its 1991 Water Quality Control Plan for the Bay-Delta Estuary, and the SWRCB intends to evaluate a range of alternative standards. Initially, we would like to evaluate the alternatives listed below, which are based on input by various parties. After the water supply and fishery impacts of these alternatives have been evaluated, additional studies may be required. Also, the SWRCB is holding a workshop on September 1, 1994 to solicit comments on alternative standards, and additional alternatives may be developed through that process.

Please be advised that the standards the SWRCB is considering may not be formulated precisely as characterized below.

<u>Alternative 1</u>

This alternative should include:

1. The water quality standards in the 1991 Water Quality Control Plan for Salinity (1991 Bay-Delta Plan);
2. The flow and export standards for the protection of fish and wildlife in D-1485;
3. The X2 isohaline standard contained in study 2' (1968 level of development with Roe Island triggered), as described in the June 10, 1994 letter from Bruce Herbold to George Barnes.
4. The salmon smolt survival standard as described in the August 17, 1994 letter from Susan Hatfield to George Barnes.

Alternative 2

This alternative should include:

1. The standards for the protection of agricultural and municipal uses in the 1991 Bay-Delta Plan;

2. The standards for the protection of Suisun Marsh contained in the water right permits of the DWR and the USBR;

3. Flows on the San Joaquin River at Vernalis for four weeks from April 17 through May 14 of 8,000, 7,000, 6,000, 5,000, and 4,000 cfs in wet, above normal, below normal, dry and critical years, respectively;

4. Maximum exports of 1,500 cfs for four weeks from April 17 through May 14;

5. Total exports for the rest of April through June not above 4,000 cfs in critical years, 5,000 cfs in dry years, and 6,000 cfs in below normal, above normal and wet years;

6. Total exports less than 9,200 cfs in July;

7. Fixed export constraints in April through July are eliminated when the Delta Outflow Index exceeds 50,000 cfs;

8. Close the Delta Cross Channel gates from November 1 through June 30;

9. Delta Outflow Indices as follows:

| Year Type | Delta Outflow Index | |
|---|---|---|
| | 12,000 cfs | 7,000 cfs |
| Wet | 2/1-6/30 | ... |
| Above Normal | 2/1-6/30 | ... |
| Below Normal | 3/15-6/15 | 3/1-3/14 and 6/16-6/30 |
| Dry | 4/1-6/10 | 3/1-3/31 and 6/11-6/30 |
| Critical | 4/15-5/15 | 3/15-4/14 and 5/16-6/15 |

10. Maximum CVP and SWP exports less than 30 percent of Delta inflow from February 1 through June 30 and 60 percent of Delta inflow from July 1 through January 30;

11. Flow on the San Joaquin River of 2,000 cfs from October 18 through October 31.

Alternative 3

This alternative is the same as Alternative 2 with one exception. The Delta outflow standard in Alternative 2 (# 9) should be replaced with the X2 isohaline standard recommended by the California Urban Water Agencies in the August 10, 1994 letter from Lyle Hoag to Harry Seraydarian.

Alternative 4

This alternative should include:

1. The standards for the protection of agricultural and municipal uses in the 1991 Bay-Delta Plan;

2 The standards for the protection of Suisun Marsh contained in the water right permits of the DWR and the USBR;

3. Close the Delta Cross Channel gates from February 1 through June 30;

4. Flow on the Sacramento River at Rio Vista of 4,000 cfs from April 1 through June 30;

5. Minimum daily flow on the Sacramento River at Freeport of 13,000 cfs from April 15 through May 31;

6. QWEST of zero cfs from February 1 through March 30;

7. QWEST of at least 1,000 cfs from April 1 through June 30 in all year types and from April 15 to May 31 QWEST of 1,500, 2,000, 2,500, 3,000 cfs in dry, below normal, above normal and wet years, respectively;

8. Flows on the San Joaquin River at Vernalis and maximum exports from April 15 through May 15 as follows:

| Year Type | Export Limit (cfs) | Flow (cfs) |
|---|---|---|
| Wet | 6,000 | 10,000 |
| Above Normal | 5,000 | 8,000 |
| Below Normal | 4,000 | 6,000 |
| Dry | 3,000 | 4,000 |
| Critical | 2,000 | 2,000 |

9. Mean Daily Delta Outflow Indices below which exports in excess of 1,500 cfs and diversions to storage would be prohibited:

| Month | Delta Outflow Index (cfs) | | | |
|---|---|---|---|---|
| | Wet | Above Normal | Below Normal | Dry |
| February | 50,000 | 50,000 | 22,200 | 19,200 |
| March | 45,000 | 50,000 | 15,400 | 15,000 |
| April | 18,000 | 13,600 | 9,500 | 9,500 |

| | | | | |
|---|---|---|---|---|
| May | 24,400 | 15,000 | 9,500 | 9,500 |
| June | 17,500 | 12,000 | 8,600 | 7,900 |
| July | 12,500 | 9,900 | 8,300 | 7,600 |
| October | 14,200 | -- | -- | -- |
| November | 16,300 | 12,900 | 9,500 | -- |
| December | 28,000 | 27,000 | 26,000 | 20,000 |

10. Delta Outflow Indices of 8,700, 7,800, 7,000, 6,200, 5,600, and 5,000 cfs in February, March, April, May, June and July of critical years;

11. Average Delta Outflow Indices (cfs) as follows:

| Year Type | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|
| Wet | 5,800 | 7,300 | 7,300 | 7,300 | 7,300 |
| Above Normal | 5,600 | 4,200 | 4,500 | 4,500 | 5,400 |
| Below Normal | 5,300 | 4,200 | 4,500 | 4,500 | 4,900 |
| Dry | 5,000 | 4,000 | 4,500 | 4,500 | 4,700 |
| Critical | 3,300 | 3,000 | 3,600 | 3,600 | 4,700 |

12. Average monthly exports (cfs) less than:

| Year Type | Apr-Jul | Aug-Mar |
|---|---|---|
| Wet | 6,400 | 7,900 |
| Above Normal | 5,400 | 7,100 |
| Below Normal | 4,400 | 6,500 |
| Dry | 3,400 | 6,000 |
| Critical | 1,600 | 5,000 |

(For standards # 9, 11, and 12, October through December should be classified based on the previous year's hydrologic index. Two of the standards in this alternative are expressed as daily standards (# 5 and 9). DWRSIM cannot directly model daily standards because it operates on a monthly time step. Please develop assumptions to model these daily standards and discuss these assumptions with me prior to beginning the study.)

Alternative 5

This alternative should include:

1. The standards for the protection of agricultural and municipal uses in the 1991 Bay-Delta Plan;

2. The standards for the protection of Suisun Marsh contained in the water right permits of the DWR and the USBR.

3. Delta Outflow Index from February 1 through June 30 of 12,000 cfs in wet, above normal, and below normal years and 7,000 cfs in dry and critical years;

4. Delta Outflow Index of 25,000 cfs for seven days in April, May, and June in wet and above normal years;

5. Delta Outflow Index of 25,000 cfs for seven days in May in below normal years;

6. Delta Outflow Index of 12,000 cfs for seven days in April, May, and June of dry or critical years unless the previous water year was dry or critically dry in which case only the May flow is required;

7. Total CVP and SWP exports during the flows described in # 4, 5, and 6 above of 3,000 cfs;

8. Flows on the Sacramento River at Freeport from September 1 through October 14 of 12,000 cfs in wet, above normal and below normal years and 8,000 cfs in dry and critical years;

9. Flows on the Sacramento River at Rio Vista from March 15 through June 15 of 7,000 cfs in wet, above normal and below normal years and 5,000 cfs in dry and critical years;

10. Flows on the San Joaquin River at Vernalis as follows:

| Year Type | Dates | Flow (cfs) |
|---|---|---|
| Wet, above normal, and below normal | 3/1-3/31 | 1,000 |
| | 4/1-5/15 | 6,000 |
| | 5/16-6/15 | 1,000 |
| | 9/1-10/31 | 2,000 |
| Dry and critical | 3/1-3/31 | 1,000 |
| | 4/1-5/15 | 3,000 |
| | 5/16-6/15 | 1,000 |
| | 9/1-10/31 | 1,000 |

11. CVP and SWP exports limited to 35 percent of Delta inflow from March 1 through June 30, 55 percent from July 1 through September 30, and 65 percent from October 1 through February 28;

12. Close the Delta Cross Channel gates from February 1 through May 20.

<u>Alternative 6</u>

This alternative eliminates all existing standards and includes the following new standards:

1. Delta Outflow Indices (cfs) as follows:

| Month | Wet | AN | BN | Dry | Critical |
|---|---|---|---|---|---|
| October | 4,500 | 4,500 | 4,500 | 3,500 | 3,500 |
| November | 4,500 | 4,500 | 4,500 | 3,500 | 3,500 |
| December | 4,500 | 4,500 | 4,500 | 3,500 | 3,500 |
| January | 4,500 | 4,500 | 4,500 | 3,500 | 3,500 |
| February | 12,000 | 12,000 | 12,000 | 12,000 | 12,000 |
| March | 12,000 | 12,000 | 12,000 | 12,000 | 12,000 |
| April | 12,000 | 12,000 | 12,000 | 12,000 | 12,000 |
| May | 12,000 | 12,000 | 12,000 | 12,000 | 12,000 |
| June | 12,000 | 12,000 | 12,000 | 12,000 | 12,000 |
| July | 7,000 | 7,000 | 4,500 | 3,500 | 3,500 |
| August | 7,000 | 7,000 | 4,500 | 3,500 | 3,500 |
| Sept | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 |

2. QWEST greater than zero cfs from February 1 through July 31, with the exception of the month of June where QWEST is greater than 4,000 cfs, and QWEST greater than -2,000 cfs from August 1 through January 31;

3. Flow on the San Joaquin River at Vernalis of 5,000 cfs from April 20 through May 10;

4. Exports limited to 2,000 cfs from April 20 through May 10;

5. Flow on the San Joaquin River at Vernalis of 2,000 cfs from October 18 through October 31;

6. Flow on the Sacramento River at Freeport of 13,000 cfs from April 15 to May 15;

7. Release 14,000 cfs from Keswick from May 1 through May 7;

8. Close the Delta Cross Channel gates from February 1 to June 30;

## Assumptions

The assumptions listed below should be incorporated into the operation studies. Please consult with me if there are additional, significant assumptions that need to be made to complete the requested studies.

1. The variable export demand option should be used. Under this option CVP and SWP demands south of the Delta are adjusted to account for hydrologic conditions in Central and Southern California.

2. The sharing formula between the CVP and SWP in the Coordinated Operation Agreement should be used except when QWEST restrictions are controlling. Export pumping rate reductions necessary to meet the QWEST standard should be shared on an equal percentage basis from a base of 6,680 cfs for the SWP and 4,600 cfs for the CVP, except when the reductions occur at the same time that fixed export limits apply in which case the export reductions are shared equally.

3. The studies should be done from two different base cases. The first base case is D-1485, and all of the alternatives should be evaluated relative to this base case. The second base case is existing conditions, which consists of D-1485, the winter-run Chinook salmon biological opinion and the Delta smelt biological opinion, including take limits. Only alternative 1 should be evaluated relative to this second base case at this time. Eventually, DWR will be asked to evaluate all of the final alternatives relative to this second base case, but this request will be deferred until the final alternatives for consideration are selected.

   The issue of take limits is complicated and not amenable to modeling; however, in DWR's written comments to the SWRCB at its May 1994 Bay-Delta workshop, DWR stated that assumptions for take limits based on operational experience during the past two years can be incorporated into the studies.

4. The water necessary to meet the pulse flow requirements on the San Joaquin River should be released from New Melones. If there is insufficient water to meet all of the requirements from this reservoir, the additional water should be provided from the San Joaquin River upstream of the confluence with the Stanislaus River. The quantity of additional water required should be identified.

5. The D-1485 base case should be modeled using D-1485 year types. The isohaline standard in Alternative 1 should be modeled using the method described in the June 10, 1994 letter from Bruce Herbold to George Barnes. The isohaline standard in Alternative 3 should be modeled in consultation with representatives from the California Urban Water Agencies. The San Joaquin River flow requirements should be modeled using the 60-20-20 San Joaquin Valley water year hydrologic classification system. All other standards should be modeled using the 40-30-30 Sacramento Valley water year hydrologic classification system.

Thank you for your consideration of this request. Please contact me at (916) 657-1873 if you have any questions.

# TABLE 1

## SUMMARY OF COMPARATIVE WATER SUPPLY IMPACTS RELATIVE TO D-1485
(1000'S AF/Year)

PRELIMINARY
8/31/94

| STATE WATER RESOURCES CONTROL BOARD STUDY | Critical Dry Period Average (May 1928 - October 1934) | 71-Year Average (1922 - 1992) | Average Annual Carryover Storage Sacramento Basin | Average Annual Carryover Storage New Melones |
|---|---|---|---|---|
| ALTERNATIVE 1 | -1093[1,3] | -490[2,3] | -174 | -727 |
| ALTERNATIVE 2 | -1555[1,3] | -645[2,3] | -195 | -672 |
| ALTERNATIVE 3 | -1386[1,3] | -569[2,3] | -253 | -672 |
| ALTERNATIVE 4 | -2604[1,3] | - | - | - |
| ALTERNATIVE 5 | -798[1,3] | -213[2,3] | -330 | -626 |
| ALTERNATIVE 6 | -1807[1,3] | -994[2,3] | +484 | -414 |

DRAFT

1. Includes adjustments due to upstream net Storage used and additional flows from Tuolumne and Merced River system to meet Vernalis pulse flows.
2. Includes adjustments due to additional flows from Tuolumne and Merced River system to meet Vernalis pulse flows.
3. Does not include potential water supply impact for "Take Limits."

## Appendix B

### Description of Northern California Hydropower Systems

**The Central Valley Project** is both a producer and consumer of hydropower in connection with its function of storing and transporting water from the Sacramento and San Joaquin River Basins for delivery to agricultural and municipal users by the U.S. Bureau of Reclamation (Bureau); the hydropower is marketed to municipal and agricultural customers by the Western Area Power Authority (Western). The CVP hydrosystem capacity is about 1,800 megawatts (MW).* The Bureau controls total daily and weekly releases from reservoirs and project pumping loads. Western determines the rate of moment-to-moment releases to optimize the value of hydropower generation.

CVP power operations are closely coordinated with the PG&E system. PG&E communicates daily with Western system dispatchers to utilize the CVP hydro system in the least-cost fashion for Northern California. This interconnection agreement is set to expire December 31, 2004.

Because negotiations over the interconnection agreement are uncertain, two sets of alternatives analyses are discussed in this report. The first uses CEC assumptions about the continuance of the PG&E-WAPA interconnection agreement as being substantially unchanged after the expiration of the contract. The second uses the assumption presented to the Board by Western and its analysts that Western no longer coordinates operations with PG&E beyond Western Systems Coordinating Council (WSCC) protocol, that Western serves its own project loads and that it sells power to its municipal and public utility customers as a separate entity meeting their requirements solely. In this latter case, the PG&E Elfin file is modified to remove the CVP pumping loads after 2004, the CVP hydro project from the data set, and to incorporate a new Western sales contract to the control area that matches the load pattern of the CVP customer group and includes a sale price set by Western. The results presented here rely on the first set of assumptions used by the CEC to be consistent with state policymaking in other arenas. Further analysis may require modelling of the second set of assumptions to further refine the expected impacts.

**The State Water Project** also produces and consumes large amounts of electricity. Managed by the DWR, the SWP delivers water from the Feather River to customers in the San Joaquin Valley and Southern California. The SWP operates a large on-stream hydro facility at Oroville and several generation recovery plants located below SWP holding reservoirs. SWP hydropower capacity is about 2,600 MW, with 900 MW at the Oroville complex on the Feather River. Most of this power is used to operate SWP pumps, including the 1,700 foot lift over the Tehachipis, or sold to the Southern California Edison Co. (SCE) and Los Angeles Department of Water and Power (LADWP). LADWP relies on the Castaic Powerplant as its single largest "peaking" plant which supplies up to 1,200 MW.

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*One megawatt equals one thousand kilowatts.

DWR has two significant contracts with SCE to supply power from Oroville and other facilities.[10] The Power Contract signed in 1979 provides SCE with 485 MW of peak capacity in exchange for energy returned to DWR during off-peak periods. The capacity-for-energy exchange rate is determined by the costs of alternative generating capacity and natural gas prices. In 1983, the Capacity Exchange Contract provided another 225 MW of capacity to SCE in return for access to up to 600 MW during off-peak periods by DWR. Both of these contracts expire at the end of 2004. According to DWR staff, agreements between DWR and SCE will not be affected by water quality standards for the Bay-Delta Estuary.

**Pacific Gas & Electric** operates 71 plants with a total capacity of 3,900 MW. This makes it the largest investor-owned hydropower system in the world and the second largest of any kind in the United States [11]. The total electric load for the PG&E system exceeds 86,000 gigawatt-hours (GWh).* PG&E's hydropower plants meet about 28% of its total demand in a typical year.

PG&E's system is integrated with plants owned by several irrigation and water districts as well as the City and County of San Francisco (CCSF). These plants total 1,300 MW of capacity. In addition, a number of small hydro facilities owned by non-electric utilities (e.g., irrigation districts) and private investors, which are collectively referred to as third-party qualifying facilities, supply power to PG&E. Third-party qualifying facilities contribute less than 2 percent of the capacity in the PG&E hydro system.**

**Other facilities**. Several municipal utilities in northern California also produce sizable amounts of hydro power.*** The largest of these is the Sacramento Municipal Utility District (SMUD), which operates plants with 650 MW of capacity. Plants with an additional 300 MW of capacity are operated by members of the Northern California Power Agency (NCPA). The largest of these is the Lake Don Pedro power plant owned by the Modesto (MID) and Turlock Irrigation Districts (TID).

The Bay-Delta standards are likely to have the most significant impacts on hydropower facilities associated with the large reservoirs that sit at the bottom of the tributary watersheds to the Sacramento and San Joaquin Rivers. Most of these large reservoirs are owned by the USBR or DWR, the largest exception being Don Pedro. PG&E and SMUD probably would not have as

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*One gigawatt-hour equals a million kilowatt-hours (KWh).

**For QFs, we have not estimated how changes in flows requirements would affect their operations due to data limitations and, as a first approximation, assume that there are no changes in generation.

***The analysis presented here excludes the direct impact on these utilities of changes in hydrological conditions since Western and the other municipal utilities are presenting the results of their own studies in these proceedings.

significant adjustments to the operations of their own reservoirs to meet the standards, although assigning responsibility to upstream diverters to meet these standards could change this outcome.

## Appendix C

### Water Project, Hydropower and Electric Utility Simulation Models

Three models were used to simulate operations of the CVP, SWP, and PG&E hydropower systems. These are briefly discussed below.

### C.1 DWRSIM

DWRSIM was used to simulate SWP operations. DWRSIM is known a *hydrological mass-balance* model because it attempts to balance the inflows and outflows for the Sacramento-San Joaquin Delta under a range of conditions and operational options. The model works on monthly time steps, simulating reservoir releases and project pumping based on a prescribed demand, a historic trace of water years, and various operational constraints and rules. DWRSIM changes the operations of the Oroville Reservoir and Clifton Court pumping station to meet the mass-balance constraints; it takes the operations of the CVP and other systems (e.g., CCSF and East Bay MUD) as given. Both DWRSIM and PROSIM used the 1922-1992 period as representative to the expected range and pattern of foreseeable water conditions.

### C.2 PROSIM

PROSIM was used to simulate CVP operations, pumping loads and power generation.* It also is a mass-balance model similar to DWRSIM, and also uses monthly time steps. PROSIM controls operations of the CVP reservoirs on the Sacramento, Trinity, American, Calaveras, and Stanislaus Rivers and pumping at Tracy while taking the operations of the SWP and other systems as given. The model was calibrated to maintain consistency with DWRSIM output.

### C.3 PG&EHELP

PG&E Hydroelectric Linear Program (PG&EHELP) is a linear program (LP) simulation model of the PG&E hydropower system. The model determines the water releases through powerhouses and spillways that will maximize the value of generated power while meeting operating constraints such as minimum stream flows, irrigation demands, maximum stream flows, and reservoir storage targets. Each independent watershed in the PG&E hydropower system is modeled. Pre-processor routines are used to automate the formulation of the LP submodels of each watershed.

PG&EHELP uses a one-month time step to maintain consistency with PROSIM, DWRSIM, and ELFIN output. The value of energy production is maximized with respect to water releases, subject to operational constraints--including continuity equations that describe the relationships

*Version 5.31 as modified by WRMI was used in this analysis.

of water flows from one reservoir to another--and price differentials between peak, partial-peak, off-peak, and super-off-peak production periods.* The model is solved using the LINDO optimization software.**

The physical units used in the model have been chosen to make the linear program solution more accurate and robust.*** The units used are hundreds of acre-feet of reservoir storage, hundreds of acre-feet per month of flow, and dollars per kilowatt-hour for electrical energy purchase prices.

The database for PG&EHELP was initially developed for a study of global climate change sponsored by EPA.[12] Core data come from the California Energy Commission's (CEC) *Electricity Report*, which provides individual unit capacity, average year generation, ownership, and river basin location.[13] The generation parameters for each unit was provided by PG&E in its *Common Forecasting Methodology* (CFM) filing with the CEC and information from other utilities and irrigation districts.[14] The CFM report shows generation by four categories: (1) PG&E-owned (2) irrigation and water districts, (3) City and County of San Francisco (which is sold to the Modesto and Turlock Irrigation Districts) and (4) Western. Requests to PG&E, USBR, CCSF, and various water and irrigation districts added information on median-year flows, minimum and maximum flow restrictions, reservoir storage and operational considerations, irrigation diversions, operational linkages between units, pump storage characteristics and calculation of kilowatt-hours (KWh) of generation per acre-foot (AF) released.[15-28]

As with any model, PG&EHELP uses several simplifying assumptions and represents an abstraction of reality. Principle assumptions are as follows:

- Optimization of the system assumes foresight of hydrologic events.

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*The system constraint equations are conceptually simple but there are a great number of them. For each powerhouse, there are minimum flow requirements for each of the four energy purchase price periods in each of twelve months. Thus there are 48 minimum flow requirements for each powerhouse. An additional 48 constraints are produced by the limitations on the maximum power generating flow that can pass through each powerhouse. There are often 12 more constraints set by the maximum river flow that is allowable below the powerhouses. Therefore there are at least 96 and often 108 or more constraints per powerhouse (not counting non-negativity constraints on all flows and storage volumes). For a watershed with 10 powerhouses this is around 1000 constraint equations.

**A FORTRAN pre-processor is used to automate the process of producing the constraint equations associated with each powerhouse and reservoir. Constraint data such as the minimum streamflow per month per energy purchase period are produced by a spreadsheet pre-processor in tabular form. These data are read by the FORTRAN pre-processor, which then generates the constraint equations.

***The SIMPLEX linear program solution method used in LINDO will suffer from round-off errors if there is too large of a range in magnitudes of the model parameters.

- Water releases of other systems (as well as energy purchase prices and capacity payments) are taken as given. In reality other systems may modify their operating behavior if they can anticipate or negotiate PG&E releases.

- Because power/storage relationships for each PG&E unit are not known, power plant production is assumed to be independent of reservoir level.

- Reservoir storage estimates do not account for inflow from small tributaries and groundwater. Similarly, reservoir release estimates do not account for evaporation and leakage.

- Where possible, maximum flow constraints are incorporated into the model, but for some facilities, this information was unavailable.

## C.4 Elfin

The Elfin production-cost model was used to forecast operations of the PG&E system.* The basic data set assumptions were those used by the CEC in their ***1994 Electricity Report*** (ER 94) forecast of average system costs.[29] All the assumptions used are consistent with the CEC Committee Order on Supply Assumptions for ER 94.[30] The fundamental resource plan was that adopted for the ***1992 Electricity Report*** with the following updates and modifications:

**Demand Forecast** - The ER 94 demand forecast for the PG&E service area was used.[31]

**Natural Gas Prices** - The ER 94 utility (UEG) natural gas price forecast was used.[32]

**Inflation** - The ER 94 inflation assumptions were used.[33]

**Purchase Energy and Capacity Availability and Prices** - The CEC staff assumptions on the price and availability of Pacific Northwest, and Southwest energy and capacity availability and prices (as adopted in the Committee Order) were used.[34]

**QF Prices** - The CEC forecast of QF prices for each utility, updated for the ER 94 natural gas forecast, was used.

**New Resources** - The characteristics and costs for the CPUC's Biennial Resource Plan Update (BRPU) auction winners, as provided by the utilities to the CEC, were used. For PG&E, the AES Pacific/San Francisco Co. cogeneration facility replaces the Hunters Point Repowering in 1997.

*Version 1.98 was used.

**Emissions** - The values for out-of-state emissions were taken from the Committee Order, while the values for California emissions were taken from CEC staff testimony.[3; 4]

The changes in hydropower generation and pumping loads were estimated based on the analysis described elsewhere in this report and used as inputs into Elfin. Table C-1 shows the change in available annual energy resources due to the proposed alternatives. In each case, resources are reduced about 350 to 450 GWH in a median year.

## C.5 Capacity Requirements and Valuation

Demand for increased capacity comes from two sources:

(1) reduced summertime generation capability on the CVP and
(2) increased agricultural pumping loads.

The required capacity additions were derived using standard electric utility planning methods, i.e., demand and supplies under dry hydrological conditions that limit hydropower generating capability.

The CVP capacity requirements and values were determined by the consultant for the Western Area Power Administration, R.W. Beck, using critically-dry water conditions. Table C-2 shows the expected additional capacity requirements to meet demand in July, and the annual net levelized cost to Western to purchase that capacity.

Table C-2
CVP Capacity Additions and Costs[1]

| Alternative | Capacity Additions | Annual Costs ($MM) |
|---|---|---|
| Alternative 1: EPA | 116 MW | $14.0MM |
| Alternative 2: SWRCB Staff | 163 MW | $21.3MM |
| Alternative 3: CUWA | 165 MW | $21.2MM |

1 - Paul Scheurmann, R.W. Beck, October 6, 1994.

The increased demand on the PG&E system from agricultural pumping is derived from the analysis in Appendix D, scaled to August demand levels. The value of capacity equals the short-run value adopted in PG&E's Energy Cost Adjustment Clause proceedings.[35] Table C-3 shows the increase in capacity requirements and costs due to increased agricultural pumping loads in dry years.* Added capacity starts at over 130 MW in 1995 and increases to over 150 MW by 2010; the cost increases from about $10 million a year to $20 million per year.

*Dry or critically dry conditions are the planning basis of electric utility capacity additions.

Table C-1
CHANGES IN POWER AVAILABILITY vs. D-1485

| Alternatives | Generation CVP Hydro GWH | Loads CVP Pumping GWH | Agriculture GW Pumping 1995 | Agriculture GW Pumping 2010 | | TOTAL GWH 1995 | TOTAL GWH 2010 |
|---|---|---|---|---|---|---|---|
| 1: EPA | | | | | | | |
| Median | -47.2 | 235.4 | -531.4 | -649.2 | | -343.2 | -461.0 |
| Dry | -19.7 | 261.6 | -568.6 | -649.2 | | -326.7 | -407.4 |
| Wet | -57.9 | 83.7 | -509.0 | -648.9 | | -483.2 | -623.2 |
| 2: SWRCB Staff | | | | | | | |
| Median | -44.5 | 251.1 | -547.3 | -652.1 | | -340.7 | -445.5 |
| Dry | 37.2 | 334.2 | -603.4 | -652.2 | | -232.0 | -280.8 |
| Wet | -93.3 | 116.6 | -517.9 | -651.9 | | -494.6 | -628.5 |
| 3: CUWA | | | | | | | |
| Median | -64.2 | 249.2 | -539.5 | -650.7 | | -354.4 | -465.6 |
| Dry | 38.3 | 322.8 | -589.8 | -650.7 | | -228.8 | -289.6 |
| Wet | -84.4 | 100.0 | -513.5 | -650.4 | | -497.9 | -634.8 |

Note: Changes shown relative to total resource availability

**Table C-3**
**Added PG&E Capacity Required for Agricultural Pumping**

| Year | D1485/NMFS | | EPA v D1485 | | SWRCB v D1485 | | CUWA v D1485 | | PG&E SO#1 |
|---|---|---|---|---|---|---|---|---|---|
| | MW | $MM | MW | $MM | MW | $MM | MW | $MM | $/KW-Yr |
| 1993 | 0 | $0.0 | 0 | $0.0 | 0 | $0.0 | 0 | $0.0 | $67.00 |
| 1994 | 112 | $7.7 | 112 | $7.7 | 112 | $7.7 | 112 | $7.7 | $69.27 |
| 1995 | 114 | $8.1 | 134 | $9.6 | 143 | $10.2 | 140 | $10.0 | $71.35 |
| 1996 | 116 | $8.5 | 136 | $9.9 | 143 | $10.5 | 140 | $10.3 | $73.34 |
| 1997 | 118 | $8.9 | 137 | $10.3 | 144 | $10.9 | 141 | $10.7 | $75.62 |
| 1998 | 120 | $9.4 | 138 | $10.8 | 144 | $11.3 | 142 | $11.1 | $78.34 |
| 1999 | 123 | $10.1 | 139 | $11.4 | 145 | $11.9 | 143 | $11.7 | $81.87 |
| 2000 | 125 | $10.6 | 140 | $11.9 | 146 | $12.4 | 144 | $12.2 | $84.81 |
| 2001 | 128 | $11.3 | 141 | $12.5 | 146 | $12.9 | 144 | $12.8 | $88.38 |
| 2002 | 130 | $12.0 | 142 | $13.1 | 147 | $13.5 | 145 | $13.4 | $92.00 |
| 2003 | 133 | $12.7 | 144 | $13.8 | 148 | $14.2 | 146 | $14.0 | $95.77 |
| 2004 | 135 | $13.5 | 145 | $14.4 | 149 | $14.8 | 147 | $14.7 | $99.60 |
| 2005 | 138 | $14.3 | 146 | $15.2 | 150 | $15.5 | 148 | $15.4 | $103.78 |
| 2006 | 140 | $15.2 | 148 | $16.0 | 150 | $16.3 | 149 | $16.2 | $108.35 |
| 2007 | 143 | $16.2 | 149 | $16.9 | 151 | $17.2 | 150 | $17.0 | $113.34 |
| 2008 | 146 | $17.4 | 151 | $18.0 | 152 | $18.2 | 152 | $18.1 | $119.66 |
| 2009 | 149 | $18.5 | 152 | $18.9 | 153 | $19.1 | 153 | $19.0 | $124.36 |
| 2010 | 151 | $19.7 | 154 | $20.0 | 154 | $20.1 | 154 | $20.1 | $130.45 |

Note: August Load Share = 17.6%

## C.6 Water-Year Type Scenarios

The economic impacts of different policy alternatives will have different outcomes depending on the type of water--year conditions used. Reductions on water deliveries in drought years typically have larger relative impacts than in wet years when excess water is available to meet environmental goals. For this reason, relying on a simple average or a single median year to measure these impacts will usually give misleading results.

In this analysis, the impacts are based on three water-year scenarios: dry, median and wet. The corresponding water conditions were chosen to match the conditions used by PG&E in its CEC filings:[14]

- for a dry year, this represents the 20 percent exceedance level (i.e., that these conditions exceed historic flows in 20 percent of past years);
- for a median year, this is the 50 percent exceedance level; and
- for a wet year, this is the 75 percent exceedance level.

The monthly streamflows, generation and pumping levels equal the average at the midpoint of the corresponding decile for the 70 year water history from 1922 to 1991.*

These results are then weighted and averaged for energy and emission results. For capacity, the dry year impacts are used solely because these are the planning basis for electric utilities in California.

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*For example, the 20 percent exceedance level equals the average of the years ranked by generation level from 11 to 17. This is done to smooth the large monthly fluctuations that may occur within a year but can greatly influence a deterministic model such as Elfin.

## Appendix D

## Estimation of Agricultural Groundwater Pumping

In the PG&E service territory, agriculture demands about 3,600 GWh in an average year; in SCE, the average demand is about 1,000 GWh. This represents about 3 percent of the load in these service areas. Upwards of 70 percent of this is related to groundwater pumping and is greatly affected by surface water availability.[36] PG&E customers are likely to bear the brunt of changes in surface water deliveries, and therefore most changes in groundwater pumping will occur in this service area.

### D.1 Econometric Groundwater Pumping Model

As shown in Figure D-1, *Groundwater Pumping*, a significant relationships exists between groundwater pumping and both natural hydrological conditions and water project deliveries. Pumping loads increased as the Sacramento River Index decreased and as project deliveries decreased over the 1970 to 1992 period. The relationship between agricultural groundwater pumping and changes in water project deliveries similar to those might be created by the policy alternatives was modelled to estimate changes in electricity demand. An econometric analysis of the relationship between PG&E loads and various water use variables was developed to measure the impacts of physical and policy factors on agricultural groundwater pumping for the 1970 to 1992 period (*Ag.GWH*).* The variables included were as follows:

- The cumulative net difference of agricultural pumping loads from the 1970 level in GWh was used as a proxy for changes in groundwater levels in the Central Valley (*Cum.GWH*).** This indicator was used because no forecast of groundwater levels was readily available. A strong correlation was found between groundwater storage levels in the San Joaquin Valley and the cumulative net difference of loads.***[37]

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*A three-stage least-squares system of equations was estimated over 23 observations. The SHAZAM 7.0 econometric computer program output for the model is available upon request.

**The equation for the cumulative net pumping difference was:

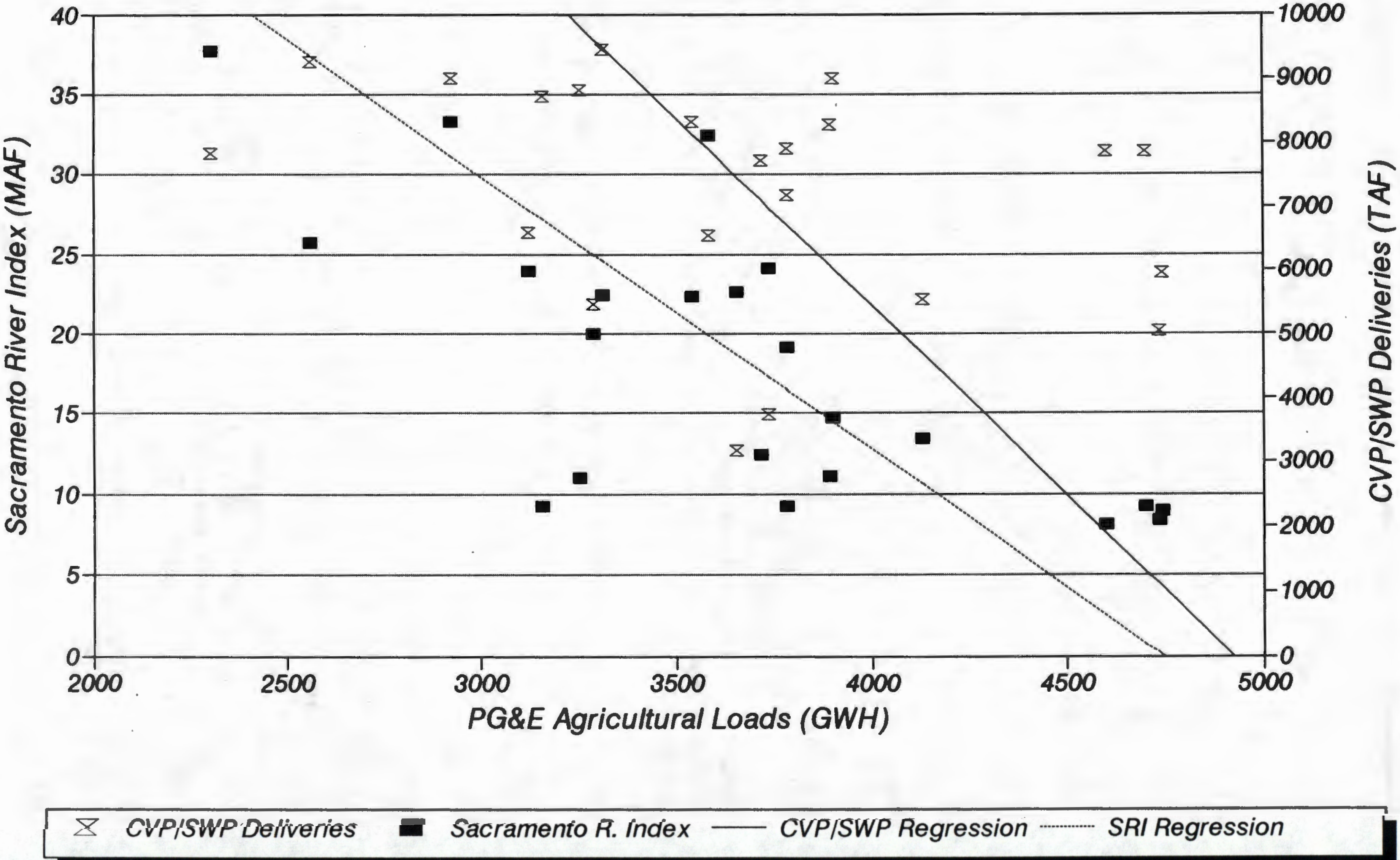
$$\text{Net Cumulative GWh}_t = (\text{GWh}_{t-1} - \text{GWh}_{1970}) + \text{Net Cumulative GWh}_{t-1}$$

*** $R^2 = -0.715$ for 1970 to 1989.

## Figure D-1

# Groundwater Pumping

### *Related to CVP/SWP & SRI - 1970-91*



- The Sacramento River Index was used as a proxy for precipitation and local water availability (*SRI*).**** Figure D-2 shows the historic distribution of Sacramento River flows.

- Total CVP and SWP project deliveries measured imported water (*Project Water*).

- The imposition of the NMFS requirements was entered as a dummy variable beginning in 1989 (*NMFS*).

The estimated model was:

$$\begin{aligned} Ag\,GWH &= 6869.2 - \underset{(5.76)}{915.95}\log(SRI) + \underset{(1.66)}{0.09822}\,Cum.GWH \\ &\quad - \underset{(2.18)}{0.10265}\,Project\ Water + \underset{(3.09)}{745.28}\,NMFS + error \\ R^2 &= 0.781 \end{aligned}$$

However, this model implied too strong of a relationship between changes in groundwater levels and groundwater pumping; if the NMFS standard is not in place, the groundwater table rises rapidly, contrary to the pre-NMFS experience.** For this reason, new parameters were solved for assuming that the groundwater table would be relatively stable in median water years without the NMFS standard in place. The resulting equation used to forecast changes in groundwater pumping is:

$$\begin{aligned} Ag\,GWH &= 6869.2 - 915.95\log(SRI) + 0.0192\,Cum.GWH \\ &\quad - 0.10265\,Project\ Water + 472.01\,NMFS + error \end{aligned}$$

---

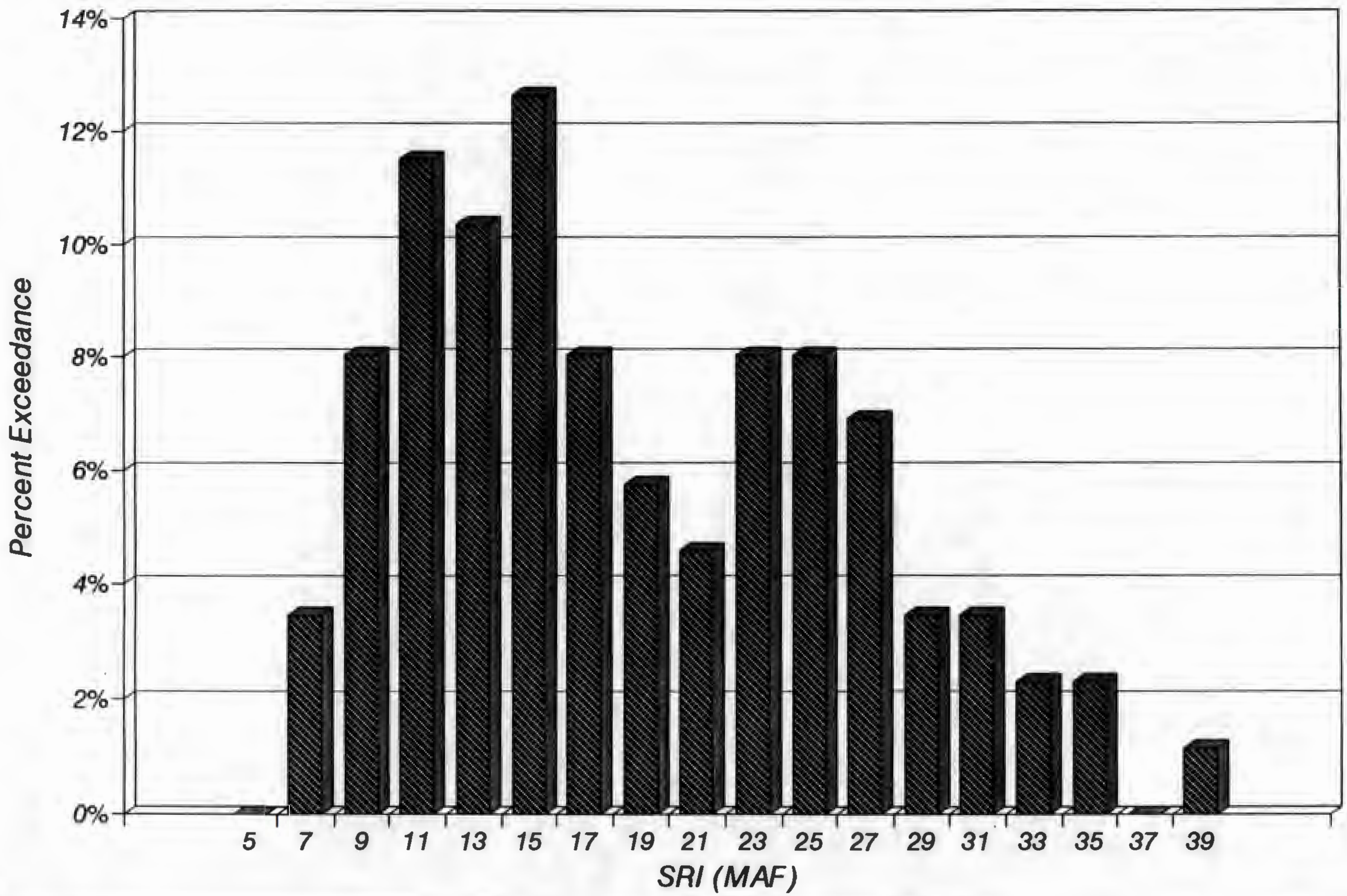
*The Sacramento River Index (SRI) has a strong correlation with the Tuolumne River flows of 0.921. The SRI was entered into the model as a logarithm to reflect how applied water rates decrease with increased precipitation at a diminishing rate.

**The NMFS opinion alone does not increase groundwater pumping--it affects the delivery of water to agriculture which in turn increases pumping. However, the inability to find this link in the aggregated annual data indicates that this influence probably occurs through seasonal shifting of water deliveries. This data was not yet available at the time this report was completed. The EPA standards could be expected to have a similar impact at the NMFS opinion, and to the extent that this occurs, the estimated impacts on agricultural pumping contained in this report are too low.

## Figure D-2

# Sacramento River Index Distribution

***1906-1991***



The model results imply certain responses by agricultural groundwater pumping to changing conditions or policies:

- a decrease of one million acre-feet (MAF) in the Sacramento River Index from median-year conditions* has lead to an increase of about 60 GWh or 1.5 percent in agricultural pumping load,
- a 50 percent curtailment of deliveries by the CVP and SWP increases agricultural loads by about 600 GWh or 15 percent,**
- the imposition of the winter-salmon and delta smelt flow requirements by the NMFS has added 470 GWh or 13 percent to agricultural loads since 1989,
- in 1995, the EPA standards would add 50 GWh to median-year pumping loads, above those from the NMFS requirements; and 88 GWh in dry years, and
- in 2010, the EPA standards would add 9 GWh in all water year types, assuming that groundwater pumping returns to 1994 levels, albeit from a deeper water table.

For example, drought conditions leading to curtailment combined with a reduction of 7 MAF in the Sacramento River Index from median conditions could increase average annual agricultural loads by about 975 GWh or over 25 percent for PG&E agricultural customers. Based on average agricultural rates in PG&E of 12.5¢ per KWh, costs to farmers would increase about $120 million.

## D.2 CVPM Agricultural Production Model

The CVPM agricultural mathematical programming model is being used by the U.S. EPA to evaluate impacts on California agricultural from alternative water quality standards. CVPM relies on input assumptions about changes in surface water and groundwater deliveries and use. The input data for the CVPM was analyzed from two perspectives to assess the changes in groundwater pumping loads. The first relied on the changes in water project deliveries and their historical relation to past groundwater pumping loads. The second used the estimated changes in groundwater pumping directly to calculate the loads based on engineering equations.

The direct calculation of the change in groundwater pumping used a common engineering equation used to estimate required pump size for farming operations.[38] The total change in

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*The median SRI water-year type for the 1906 to 1992 time period is 15.8 MAF.

**Curtailment on the CVP and the SWP is defined as restriction of deliveries below current firm yield on these systems as defined by the relevant contracts.

agricultural groundwater pumping load for the Central Valley was estimated based on the equation:

*Kilowatt-hours/Acre-foot = 1.0231 * (depth + 2.31*irrigation PSI)/pump efficiency*

where depth is region specific plus 30 feet for drawdown, irrigation system pressures (PSI) were derived for each region based on cropping patterns, and an average pumping efficiency of 70 percent was used.* The input data and results from CVPM are shown in the three attached tables.

The CVPM estimate approximates that from the adjusted econometric model. Based on the estimate made from the CVPM model, groundwater pumping increases by 115 GWh in 1995 under median-year conditions and by 133 GWh in dry years; this falls to zero in 2010 based on the assumption that groundwater pumping is held to pre-EPA standard levels.

*The CVPM groundwater input data for 1995 and 2010, and the estimates of irrigation pressures are included the attached tables.

| DAU | Utility | 1990 | Ave. | 1995 Base (D1485 & NMFS) | | | 1995 EPA Standards | | | 2010 Base (D1485 & NMFS) | | | 2010 EPA Standards | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sum | | Lift(Ft) | PSI | Dry: Yr 7 | Median | Wet | Dry: Yr 7 | Median | Wet | Dry: Yr 7 | Median | Wet | Dry: Yr 7 | Median | Wet |
| Note: | | (1) | (6) | (4) | | | | | | | | | | | |
| R1 | PG&E | 70 | 8.7 | 8.43 | 8.43 | 8.43 | 8.43 | 8.43 | 8.43 | 8.43 | 8.43 | 8.43 | 8.43 | 8.43 | 8.43 |
| R2 | PG&E | 100 | 8.7 | 75.95 | 75.58 | 75.73 | 75.95 | 75.58 | 75.73 | 75.95 | 75.58 | 75.73 | 75.95 | 75.58 | 75.73 |
| R3 | PG&E | 95 | 8.7 | 75.70 | 73.41 | 73.18 | 75.70 | 73.41 | 73.18 | 75.70 | 73.41 | 73.18 | 75.70 | 73.41 | 73.18 |
| R4 | PG&E | 40 | 8.7 | 30.04 | 27.49 | 30.73 | 30.04 | 27.49 | 30.73 | 30.04 | 27.49 | 30.73 | 30.04 | 27.49 | 30.73 |
| R5 | PG&E | 40 | 8.7 | 102.41 | 99.23 | 100.95 | 102.41 | 99.23 | 100.95 | 102.41 | 99.23 | 100.95 | 102.41 | 99.23 | 100.95 |
| R6 | PG&E | 120 | 8.7 | 151.47 | 151.47 | 151.47 | 151.47 | 151.47 | 151.47 | 151.47 | 151.47 | 151.47 | 151.47 | 151.47 | 151.47 |
| R7 | PG&E | 80 | 8.7 | 47.03 | 45.31 | 45.07 | 47.03 | 45.31 | 45.07 | 47.03 | 45.31 | 45.07 | 47.03 | 45.31 | 45.07 |
| R8 | PG&E/SMUD | 120 | 12.0 | 244.89 | 244.89 | 244.89 | 244.89 | 244.89 | 244.89 | 244.89 | 244.89 | 244.89 | 244.89 | 244.89 | 244.89 |
| R9 | PG&E | 100 | 12.0 | 73.75 | 73.75 | 73.75 | 73.75 | 73.75 | 73.75 | 73.75 | 73.75 | 73.75 | 73.75 | 73.75 | 73.75 |
| R10 | PG&E | 120 | 12.0 | 88.84 | 62.87 | 79.56 | 130.48 | 99.54 | 77.44 | 64.46 | 42.92 | 42.43 | 64.46 | 42.92 | 42.43 |
| R11 | MID | 100 | 12.0 | 75.99 | 68.51 | 61.67 | 75.99 | 68.51 | 61.67 | 75.99 | 68.51 | 61.67 | 75.99 | 68.51 | 61.67 |
| R12 | TID | 90 | 12.0 | 45.88 | 44.91 | 42.55 | 45.88 | 44.91 | 42.55 | 45.88 | 44.91 | 42.55 | 45.88 | 44.91 | 42.55 |
| R13 | PG&E | 120 | 12.0 | 294.32 | 279.70 | 190.23 | 295.19 | 280.35 | 190.06 | 293.56 | 279.65 | 191.05 | 293.56 | 279.65 | 191.05 |
| R14 | PG&E | 300 | 11.9 | 203.22 | 161.66 | 176.68 | 273.64 | 214.91 | 176.81 | 130.06 | 96.48 | 105.07 | 130.06 | 96.48 | 105.07 |
| R15 | PG&E | 300 | 11.9 | 662.96 | 654.68 | 634.06 | 664.17 | 655.83 | 634.18 | 657.60 | 652.02 | 637.02 | 657.60 | 652.02 | 637.02 |
| R16 | PG&E | 100 | 11.9 | 74.05 | 66.52 | 61.32 | 75.28 | 67.44 | 61.32 | 74.81 | 67.99 | 57.32 | 74.81 | 67.99 | 57.32 |
| R17 | PG&E | 100 | 11.9 | 127.35 | 118.55 | 82.39 | 127.35 | 118.55 | 82.39 | 127.35 | 118.55 | 82.39 | 127.35 | 118.55 | 82.39 |
| R18 | SCE | 150 | 11.9 | 364.41 | 360.41 | 344.27 | 366.31 | 361.84 | 344.28 | 364.37 | 361.41 | 339.47 | 364.37 | 361.41 | 339.47 |
| R19 | PG&E | 300 | 11.9 | 233.05 | 145.80 | 99.02 | 241.37 | 156.84 | 102.24 | 143.26 | 113.31 | 110.50 | 143.26 | 113.31 | 110.50 |
| R20 | SCE | 300 | 11.9 | 154.30 | 145.91 | 102.56 | 154.60 | 146.31 | 102.67 | 149.03 | 143.15 | 102.73 | 149.03 | 143.15 | 102.73 |
| R21 | SCE | 350 | 11.9 | 636.88 | 540.70 | 289.57 | 644.04 | 550.18 | 292.34 | 567.97 | 514.38 | 298.22 | 567.97 | 514.38 | 298.22 |
| Total | | | | 3,771 | 3,450 | 2,968 | 3,904 | 3,565 | 2,972 | 3,504 | 3,303 | 2,875 | 3,504 | 3,303 | 2,875 |
| | PG&E | | | 2,493 | 2,289 | 2,127 | 2,617 | 2,393 | 2,129 | 2,301 | 2,170 | 2,030 | 2,301 | 2,170 | 2,030 |
| | SCE | | | 1,156 | 1,047 | 736 | 1,165 | 1,058 | 739 | 1,081 | 1,019 | 740 | 1,081 | 1,019 | 740 |
| | MID/TID | | | 122 | 113 | 104 | 122 | 113 | 104 | 122 | 113 | 104 | 122 | 113 | 104 |
| | SMUD | | | | | | | | | | | | | | |
| | v. Median | | | 321 | | (482) | | | | 201 | | (428) | | | |
| | EPA v. Base | | | | | | 133 | 115 | 4 | | | | 0 | 0 | 0 |

CVPM Ag. Model Groundwater Pumping

| Crop | Region (Thousand Acres) | | | Irr. Method | | | |
|---|---|---|---|---|---|---|---|
| | SR (7) | SJ | TL | Surface (8) | Sprinkler | Drip | Subsurf. |
| Grain | 303 | 182 | 297 | 88.8% | 10.8% | 0.0% | 0.4% |
| Rice | 494 | 21 | 1 | 100.0% | 0.0% | 0.2% | 0.0% |
| Cotton | 0 | 178 | 1029 | 93.3% | 6.5% | 0.0% | 0.0% |
| Sugar Beets | 75 | 64 | 35 | 86.7% | 13.3% | 0.0% | 0.0% |
| Corn | 104 | 181 | 100 | 99.1% | 0.0% | 0.0% | 0.9% |
| Field | 155 | 121 | 135 | 89.5% | 9.3% | 0.7% | 0.5% |
| Alfalfa | 141 | 226 | 345 | 86.0% | 13.0% | 0.0% | 0.9% |
| Pasture | 357 | 228 | 44 | 81.8% | 12.0% | 0.0% | 6.2% |
| Tomatoes | 120 | 89 | 107 | 92.7% | 6.5% | 0.9% | 0.0% |
| Truck | 55 | 133 | 204 | 55.1% | 29.5% | 15.4% | 0.0% |
| Almonds/Pistachios | 101 | 245 | 164 | 39.2% | 47.3% | 13.2% | 0.2% |
| Fruit | 205 | 147 | 177 | 39.2% | 47.3% | 13.2% | 0.2% |
| Citrus/Olives | 18 | 9 | 181 | 11.5% | 80.6% | 7.9% | 0.0% |
| Grapes | 17 | 184 | 393 | 44.9% | 12.7% | 42.2% | 0.3% |
| | 2145 | 2008 | 3212 | | | | |
| Basin (HSA) | | | | | | | |
| Sacramento River | | | | 81.8% | 14.2% | 2.8% | 1.3% |
| San Joaquin Valley | | | | 73.0% | 18.4% | 7.6% | 1.0% |
| Tulare Lake | | | | 73.2% | 18.4% | 8.0% | 0.3% |
| Ave.PSI | 8.7 | 12.0 | 11.9 | 3 | 30 | 50 | 50 |

(7) CDWR Bulletin 160-93, T.7-12.
(8) CDWR Bulletin 160-93, T.7-8.

CVPM Ag. Model Groundwater Pumping

| DAU | Utility | 1990 | Ave. | GW Pumping: (TAF) 1995 Base (D1485 & NMFS) | | | 1995 EPA Standards | | | 2010 Base (D1485 & NMFS) | | | 2010 EPA Standards | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sum | | Lift(Ft) | PSI | Dry: Yr 7 | Median | Wet | Dry: Yr 7 | Median | Wet | Dry: Yr 7 | Median | Wet | Dry: Yr 7 | Median | Wet |
| Note: | | (1) | (6) | (2) | (2) | (2) | (2) | (2) | (2) | (3) | (3) | (3) | (3) | (3) | (3) |
| R1 | PG&E | 70 | 8.7 | 48.00 | 48.00 | 48.00 | 48.00 | 48.00 | 48.00 | 48.00 | 48.00 | 48.00 | 48.00 | 48.00 | 48.00 |
| R2 | PG&E | 100 | 8.7 | 346.03 | 344.35 | 345.05 | 346.03 | 344.35 | 345.05 | 346.03 | 344.35 | 345.05 | 346.03 | 344.35 | 345.05 |
| R3 | PG&E | 95 | 8.7 | 356.79 | 346.00 | 344.89 | 356.79 | 346.00 | 344.89 | 356.79 | 346.00 | 344.89 | 356.79 | 346.00 | 344.89 |
| R4 | PG&E | 40 | 8.7 | 227.92 | 208.63 | 233.20 | 227.92 | 208.63 | 233.20 | 227.92 | 208.63 | 233.20 | 227.92 | 208.63 | 233.20 |
| R5 | PG&E | 40 | 8.7 | 777.05 | 752.94 | 765.99 | 777.05 | 752.94 | 765.99 | 777.05 | 752.94 | 765.99 | 777.05 | 752.94 | 765.99 |
| R6 | PG&E | 120 | 8.7 | 609.00 | 609.00 | 609.00 | 609.00 | 609.00 | 609.00 | 609.00 | 609.00 | 609.00 | 609.00 | 609.00 | 609.00 |
| R7 | PG&E | 80 | 8.7 | 247.19 | 238.14 | 236.89 | 247.19 | 238.14 | 236.89 | 247.19 | 238.14 | 236.89 | 247.19 | 238.14 | 236.89 |
| R8 | PG&E/SMUD | 120 | 12.0 | 943.00 | 943.00 | 943.00 | 943.00 | 943.00 | 943.00 | 943.00 | 943.00 | 943.00 | 943.00 | 943.00 | 943.00 |
| R9 | PG&E | 100 | 12.0 | 320.00 | 320.00 | 320.00 | 320.00 | 320.00 | 320.00 | 320.00 | 320.00 | 320.00 | 320.00 | 320.00 | 320.00 |
| R10 | PG&E | 120 | 12.0 | 342.08 | 242.09 | 306.35 | 502.43 | 383.28 | 298.21 | 248.23 | 165.28 | 163.40 | 248.23 | 165.28 | 163.40 |
| R11 | MID | 100 | 12.0 | 329.73 | 297.26 | 267.57 | 329.73 | 297.26 | 267.57 | 329.73 | 297.26 | 267.57 | 329.73 | 297.26 | 267.57 |
| R12 | TID | 90 | 12.0 | 212.57 | 208.05 | 197.14 | 212.57 | 208.05 | 197.14 | 212.57 | 208.05 | 197.14 | 212.57 | 208.05 | 197.14 |
| R13 | PG&E | 120 | 12.0 | 1133.33 | 1077.03 | 732.50 | 1136.67 | 1079.53 | 731.85 | 1130.41 | 1076.85 | 735.65 | 1130.41 | 1076.85 | 735.65 |
| R14 | PG&E | 300 | 11.9 | 389.00 | 309.44 | 338.19 | 523.78 | 411.37 | 338.43 | 248.96 | 184.68 | 201.11 | 248.96 | 184.68 | 201.11 |
| R15 | PG&E | 300 | 11.9 | 1269.00 | 1253.14 | 1213.68 | 1271.32 | 1255.35 | 1213.90 | 1258.74 | 1248.05 | 1219.35 | 1258.74 | 1248.05 | 1219.35 |
| R16 | PG&E | 100 | 11.9 | 321.80 | 289.06 | 266.48 | 327.12 | 293.08 | 266.46 | 325.08 | 295.44 | 249.11 | 325.08 | 295.44 | 249.11 |
| R17 | PG&E | 100 | 11.9 | 553.41 | 515.19 | 358.03 | 553.41 | 515.19 | 358.03 | 553.41 | 515.19 | 358.03 | 553.41 | 515.19 | 358.03 |
| R18 | SCE | 150 | 11.9 | 1201.92 | 1188.72 | 1135.49 | 1208.16 | 1193.44 | 1135.51 | 1201.77 | 1192.01 | 1119.64 | 1201.77 | 1192.01 | 1119.64 |
| R19 | PG&E | 300 | 11.9 | 446.08 | 279.09 | 189.54 | 462.01 | 300.22 | 195.71 | 274.21 | 216.90 | 211.51 | 274.21 | 216.90 | 211.51 |
| R20 | SCE | 300 | 11.9 | 295.35 | 279.30 | 196.31 | 295.92 | 280.06 | 196.53 | 285.26 | 274.01 | 196.63 | 285.26 | 274.01 | 196.63 |
| R21 | SCE | 350 | 11.9 | 1069.48 | 907.96 | 486.26 | 1081.49 | 923.89 | 490.91 | 953.76 | 863.77 | 500.79 | 953.76 | 863.77 | 500.79 |
| Total | | | | 11,439 | 10,656 | 9,534 | 11,780 | 10,951 | 9,536 | 10,897 | 10,348 | 9,266 | 10,897 | 10,348 | 9,266 |
| | PG&E | | | 8,330 | 7,775 | 7,251 | 8,652 | 8,048 | 7,249 | 7,914 | 7,512 | 6,984 | 7,914 | 7,512 | 6,984 |
| | SCE | | | 2,567 | 2,376 | 1,818 | 2,586 | 2,397 | 1,823 | 2,441 | 2,330 | 1,817 | 2,441 | 2,330 | 1,817 |
| | MID/TID | | | 542 | 505 | 465 | 542 | 505 | 465 | 542 | 505 | 465 | 542 | 505 | 465 |
| | SMUD | | | (5) | | | | | | | | | | | |
| | v. Median | | | 782 | | (1,123) | | | | 550 | | (1,082) | | | |
| | EPA v. Base | | | | | | 341 | 294 | 3 | | | | 0 | 0 | 0 |

(1) Per Steve Hatchett, CH2M Hill 7/6/94 add 30ft drawdown.
(2) Per Larry Dale, for US EPA 8/22/94; reliminary for three water-yr types.
(3) Per Dale; assumes pumping at equilib ium in 2010.
(4) KWH/AF = 1.0231 x (lift+draw+2.306 2*PSI)/efficieny; ave. efficiency=70%
(5) Assume that most pumping in R8 by G&E ag. customers.
(6) Ave. PSI based on allocated irrigation ethods and crops by region from Bulletin 160-93.

## Appendix E

### Potential Impacts on PG&E Thermal Plant Cooling Water Diversions

Two large PG&E natural-gas-fired thermal generating plants could be affected by the salinity standards. The Contra Costa facility situated in Antioch has 1,260 MW that relies on once-through cooling water drawn from the Delta. The Pittsburg facility has 1,302 MW that uses once-through cooling plus another 720 MW unit that relies on cycled-water. This latter plant is less likely to be affected by any diversion restrictions. Combined, the once-through units in the Bay-Delta region represent about 16 percent of PG&E's generating resources.

Currently, PG&E constrains operations at these two plants during April and May to reduce fish entrapment.[11, , p. 2-30] These months are also the lowest load periods of the year. If PG&E had to restrict generation during the summer months however, several problems could arise. First, these units are critical to maintaining voltage levels for PG&E's largest load centers in the Bay Area. The plants sit in the middle of the PG&E service area and act to boost the power delivered from the state's hydropower and imported energy from the Pacific Northwest. Second, the plants provide reliability in case the Bay Area is disconnected from the rest of the utility system's resources. The Contra Costa and Pittsburg plants must be up and running to fill these requirements.* On particularly hot days in the summer, system voltage can "sag" causing customer equipment failures if these units are not operating near full load. The alternative would be to either (1) build more generating capacity near the Bay Area that has a cooling water source independent of Delta water sources or (2) rely more on customer curtailments during peak load periods.

Changes in the intake restrictions at the PG&E plants in the Delta are not modelled here do to the uncertainty of the impacts. However, this issue should be examined in the future as more information is developed to assess the implications for the entire electricity system.

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*On June 10, 1994, PG&E was just one "contingency" (i.e., one generating plant or transmission interconnection) away from shutting down its power grid in the Bay Area. This coincided with the generation restrictions at the Contra Costa and Pittsburg units.

## Appendix F

## Detailed Results for the Comparison of Alternatives to Base Case Conditions

The following tables show the annual cost and emission impacts from Elfin for each alternative evaluated in this report. The costs are broken out by energy and emissions. The emission data shows NOx, SOx, ROG, PM10 and carbon. Tables are included for expected conditions based on a weighted average of the three water-year types.

| TABLE F-1. NET INCREASE IN EMISSIONS DUE TO EPA FLOWS. NORTHERN CALIFORNIA SYSTEM EXAMPLE | | | | | |
|---|---|---|---|---|---|
| | TONS PER YEAR: Probability Weighted(1) | | | | |
| | NOx | SOx | PM10 | ROG | Cx |
| 1995 | 231.61 | 80.57 | 7.84 | 5.57 | 42,427.35 |
| 1996 | 208.46 | 58.66 | 7.96 | 6.02 | 46,983.95 |
| 1997 | 119.35 | 65.03 | 9.29 | 6.83 | 50,543.40 |
| 1998 | 85.72 | 59.78 | 8.49 | 5.48 | 57,037.20 |
| 1999 | 103.57 | 40.10 | 8.83 | 6.72 | 52,048.45 |
| 2000 | 119.80 | 57.46 | 8.96 | 5.83 | 55,491.43 |
| 2001 | 73.60 | 35.42 | 8.69 | 6.37 | 59,980.98 |
| 2002 | 117.11 | 49.53 | 8.61 | 5.51 | 60,619.40 |
| 2003 | 90.10 | 46.65 | 9.46 | 6.27 | 65,079.93 |
| 2004 | 73.66 | 10.19 | 8.89 | 7.01 | 70,244.85 |
| 2005 | 121.24 | 49.17 | 7.80 | 4.47 | 64,360.98 |
| 2006 | 135.05 | 43.52 | 8.70 | 5.27 | 64,640.23 |
| 2007 | 234.80 | 62.76 | 11.14 | 4.36 | 57,399.48 |
| 2008 | 113.23 | 58.86 | 8.70 | 4.92 | 65,113.00 |
| 2009 | 126.14 | 58.42 | 9.15 | 5.01 | 66,983.68 |
| 2010 | 155.61 | 70.30 | 9.29 | 5.02 | 67,790.03 |
| 2011 | 129.68 | 52.80 | 8.10 | 3.99 | 66,503.55 |
| AVE | 131.69 | 52.90 | 8.82 | 5.57 | 59,602.81 |

(1) 20% DRY, 55% NORMAL, 25% WET YEAR

**TABLE F-2. PRODUCTION COST IMPACT OF EPA FLOWS. NORTHERN CALIFORNIA**

| | ($ MILLION) (1) | | |
|---|---|---|---|
| | Production | Emissions | Total |
| 1995 | $10.22 | $2.21 | $16.10 |
| .1996 | $17.55 | $2.23 | $23.55 |
| 1997 | $14.86 | $2.36 | $21.11 |
| 1998 | $22.74 | $2.43 | $29.18 |
| 1999 | $12.53 | $2.70 | $19.39 |
| 2000 | $21.06 | $2.93 | $28.30 |
| 2001 | $19.07 | $2.93 | $26.50 |
| 2002 | $24.03 | $3.51 | $32.22 |
| 2003 | $23.60 | $3.64 | $32.12 |
| 2004 | $24.80 | $4.18 | $34.06 |
| 2005 | $21.13 | $4.28 | $30.69 |
| 2006 | $28.88 | $4.57 | $38.95 |
| 2007 | $36.67 | $3.55 | $45.97 |
| 2008 | $28.67 | $4.61 | $39.28 |
| 2009 | $37.85 | $5.23 | $49.36 |
| 2010 | $42.61 | $5.63 | $54.83 |
| AVE | $24.14 | $3.56 | ~~$32.60~~ $27 M |
| NPV | $152.55 | $22.92 | $208.67 |

(1) PROBABILITY WEIGHTED: 20% DRY,
55% NORMAL, 25 % WET.

not added correct

| TABLE F-3. NET INCREASE IN EMISSIONS DUE TO SWRCB FLOWS. NORTHERN CALIFORNIA SYSTEM EXAMPLE | | | | | |
|---|---|---|---|---|---|
| | TONS PER YEAR: Probability Weighted(1) | | | | |
| | NOx | SOx | PM10 | ROG | Cx |
| 1995 | 183.06 | 72.58 | 7.96 | 6.10 | 42,945.88 |
| 1996 | 199.31 | 62.85 | 8.41 | 6.47 | 47,770.50 |
| 1997 | 130.79 | 64.26 | 8.98 | 6.70 | 49,202.33 |
| 1998 | 92.42 | 64.97 | 9.40 | 6.77 | 53,618.53 |
| 1999 | 108.66 | 49.72 | 9.79 | 7.78 | 50,110.88 |
| 2000 | 172.13 | 64.77 | 10.13 | 7.34 | 54,759.95 |
| 2001 | 132.38 | 54.82 | 9.51 | 7.09 | 58,555.25 |
| 2002 | 126.01 | 62.67 | 9.81 | 7.01 | 57,489.20 |
| 2003 | 113.58 | 52.10 | 9.94 | 7.37 | 60,189.05 |
| 2004 | 92.83 | 10.51 | 8.61 | 7.17 | 58,550.63 |
| 2005 | 125.51 | 49.90 | 9.32 | 6.19 | 62,290.98 |
| 2006 | 152.23 | 56.13 | 9.62 | 6.40 | 61,348.70 |
| 2007 | 229.98 | 211.19 | 12.15 | 5.71 | 53,801.83 |
| 2008 | 135.45 | 67.98 | 8.95 | 5.16 | 62,458.30 |
| 2009 | 151.52 | 69.93 | 10.05 | 6.15 | 62,024.03 |
| 2010 | 163.17 | 69.20 | 10.04 | 6.13 | 65,993.20 |
| | | | | | |
| AVE | 144.31 | 67.72 | 9.54 | 6.60 | 56,319.33 |

(1) 20% DRY, 55% NORMAL, 25% WET YEAR

| TABLE F-4. PRODUCTION COST IMPACT OF SWRCB FLOWS. NORTHERN CALIFORNIA | | | |
|---|---|---|---|
| | $MILLION PER YEAR (1) | | |
| | Production | Emissions | Total |
| 1995 | $10.98 | $1.98 | $12.95 |
| 1996 | $16.37 | $2.31 | $18.67 |
| 1997 | $10.88 | $2.37 | $13.25 |
| 1998 | $23.19 | $2.31 | $25.50 |
| 1999 | $17.48 | $2.63 | $20.11 |
| 2000 | $19.22 | $3.36 | $22.58 |
| 2001 | $17.63 | $3.21 | $20.84 |
| 2002 | $22.75 | $3.36 | $26.11 |
| 2003 | $24.07 | $3.61 | $27.67 |
| 2004 | $20.56 | $3.80 | $24.36 |
| 2005 | $21.89 | $4.27 | $26.16 |
| 2006 | $27.62 | $4.52 | $32.15 |
| 2007 | $29.73 | $3.38 | $33.11 |
| 2008 | $26.77 | $4.62 | $31.38 |
| 2009 | $32.28 | $5.19 | $37.47 |
| 2010 | $33.08 | $5.65 | $38.73 |
| | | | |
| AVE | $22.16 | $3.53 | $25.69 |
| NPV | $143.74 | $22.75 | $166.50 |
| (1) 20% DRY, 55% NORMAL, 25% WET YEAR | | | |

| TABLE F-5. NET INCREASE IN EMISSIONS DUE TO CUWA FLOWS. NORTHERN CALIFORNIA SYSTEM EXAMPLE | | | | | |
|---|---|---|---|---|---|
| | TONS PER YEAR: Probability Weighted(1) | | | | |
| | NOx | SOx | PM10 | ROG | Cx |
| 1995 | 186.54 | 60.53 | 7.81 | 6.00 | 46,199.70 |
| 1996 | 213.81 | 58.93 | 7.40 | 5.41 | 47,843.18 |
| 1997 | 147.08 | 82.33 | 9.51 | 7.11 | 47,219.38 |
| 1998 | 139.47 | 84.87 | 9.12 | 6.07 | 51,649.85 |
| 1999 | 99.50 | 58.71 | 8.50 | 6.07 | 49,257.25 |
| 2000 | 150.52 | 77.30 | 9.18 | 5.91 | 53,632.40 |
| 2001 | 137.66 | 70.28 | 9.32 | 6.34 | 58,829.30 |
| 2002 | 131.25 | 67.53 | 8.46 | 5.38 | 58,369.25 |
| 2003 | 120.71 | 60.80 | 9.99 | 7.20 | 60,823.18 |
| 2004 | 96.24 | 16.14 | 8.23 | 6.66 | 59,034.05 |
| 2005 | 120.41 | 53.65 | 7.72 | 4.30 | 63,095.18 |
| 2006 | 147.36 | 54.25 | 8.27 | 4.84 | 61,570.10 |
| 2007 | 233.03 | 226.18 | 11.23 | 4.25 | 53,235.30 |
| 2008 | 130.97 | 70.37 | 7.90 | 3.89 | 63,157.60 |
| 2009 | 148.40 | 74.13 | 9.15 | 4.94 | 62,983.63 |
| 2010 | 179.22 | 90.87 | 9.35 | 4.76 | 65,136.45 |
| | | | | | |
| AVE | 148.88 | 75.43 | 8.82 | 5.57 | 56,377.24 |
| (1) 20% DRY, 55% NORMAL, 25% WET YEAR | | | | | |

| TABLE F-6. PRODUCTION COST IMPACT OF CUWA FLOWS. NORTHERN CALIFORNIA | | | |
|---|---|---|---|
| | $MILLION PER YEAR(1) | | |
| | Production | Emissions | Total |
| 1995 | $11.13 | $2.14 | $13.27 |
| 1996 | $15.88 | $2.23 | $18.11 |
| 1997 | $13.14 | $2.39 | $15.53 |
| 1998 | $22.29 | $2.41 | $24.69 |
| 1999 | $13.42 | $2.38 | $15.80 |
| 2000 | $20.31 | $3.01 | $23.32 |
| 2001 | $15.56 | $3.18 | $18.74 |
| 2002 | $19.92 | $3.39 | $23.30 |
| 2003 | $26.59 | $3.43 | $30.02 |
| 2004 | $25.07 | $4.15 | $29.22 |
| 2005 | $21.63 | $4.05 | $25.68 |
| 2006 | $29.35 | $4.41 | $33.76 |
| 2007 | $31.85 | $3.24 | $35.09 |
| 2008 | $27.41 | $4.58 | $32.00 |
| 2009 | $34.57 | $5.05 | $39.62 |
| 2010 | $37.71 | $5.48 | $43.19 |
| | | | |
| AVE | $22.86 | $3.47 | $26.33 |
| NPV | $145.53 | $22.42 | $167.95 |
| (1) 20% DRY, 55% NORMAL, 25% WET YEAR | | | |

## Appendix G

## Critique of the Electric Power Analysis in the Evaluation of Economic Impacts of the Winter-Run Salmon CHD

The ***Evaluation of Economic Impacts of Alternatives for Designation of Winter-Run Salmon Critical Habitat in the Sacramento River*** was done for NOAA and NMFS by Hydrosphere Resource Consultants and used in the Regulatory Impact Analysis (RIA).[8] The annual benefits to electricity generation and use would be $48.9 million according to the report. However, the Hydrosphere report made several mistakes that lead to incorrect conclusions about the impacts of the CHD on the state's electric power system. These problems occur because standard electric utility planning methods were not applied in the analysis.

(1) The PROSIM simulation used in the analysis shows a single two-year period (1936-37) increase of over 1,300 gigawatt-hours (GWh or million kilowatt-hours) per year. This power would be of little, if any, value to Northern California due to hydropower spill conditions. In addition, these changes were by far the largest in the simulation. Removing these two years alone as outliers from the average change in generation over the entire 55-year period (1922-1978) changes the increase hydropower from 18 GWH to a loss of 6 GWH.

(2) The energy output is not valued with time-period specific prices. As discussed in Section 2.0 above, the value of energy can vary significantly by season and time of day. The Hydrosphere report does not apply this principle in evaluating the economic impacts.

(3) Dry year impacts, while significant and of greater relative value to electric utilities, were not discussed in the report; only averages were conveyed. The impacts during drought periods were substantial in the 1929 to 1934 and 1976 to 1977 periods. In the first period, the average losses were 320 GWH per year; in the second, 524 GWH; these represent 10 to 20 percent of critically-dry period generation from the CVP.

(4) Electricity utility standard practice rate the capacity available from the hydro system in a critically dry year during the peak load month (i.e., July)--this usually equals the minimum expected capacity from a facility. The Hydrosphere report uses the change in average capacity as a measure of capacity value. This information was not available in the Hydrosphere report, but the decrease in generation in drought years indicates large potential losses in capacity as well.

(5) Only the change in groundwater pumping for Sacramento River exchange contractors was included due to a reliance on the PROSIM model as representative of these impacts. In fact groundwater pumping by other CVP contractors in the Sacramento and San Joaquin Valleys is not included in the PROSIM model, and these changes must be estimated from PG&E load data.

An examination of the recent electricity generation and use patterns shows how the Hydrosphere report reached misleading conclusions. Both hydropower generation and agricultural groundwater pumping have realized large cost impacts rather than benefits identified in the report.

In an effort to assure the survival of several salmon runs in the Sacramento River--particularly the winter-run--temperatures in the river must be held below about 56 degrees F. To meet this constraint, the Bureau releases cooler water from the bottom of Lake Shasta during the summer. Doing so required that the electricity-generation turbines be bypassed and power generation be foregone. In addition, cooler water was released through Trinity Dam to supplement these flows since 1991.

Both the Bureau and the Western have estimated the losses in energy and purchased-power replacement costs.* The latter represents energy that Western had to buy to meet its contract agreement with municipal utilities (e.g., SMUD) and irrigation customers. The energy losses have been about 13 percent of the total potential energy output from the unit. The added purchase power costs in net present value have amounted to about $44 million over the 1987-1993 period.** This calculation ignores the additional capacity purchases that Western made to make up any shortfalls during these periods, and any efficiency losses from reduced hydropower head.*** Capacity is of particular importance because most of these bypasses occurred during the summer when electricity demand is at its highest level.****

In addition, as discussed in Appendix D, agricultural groundwater pumping increased substantially in the same time period. Statistical analysis finds that agricultural loads have increased at least 470 GWH since 1988 due to the imposition of the NMFS opinions. Based on an average avoided energy cost of 2.5 cents per kilowatt-hour and $60 per kilowatt of capacity, the annual cost has been $17 million in added resource expenditures in the PG&E system alone. The net present value total through 1993 is about $106 million.

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*USBR, "Shasta Powerplant Bypass Data," Preliminary Draft, June 17, 1994; and James C. Feider, Area Manager, Western Area Power Administration, "Comments to SWRCB Bay/Delta Workshop," June 14, 1994.

**Assuming a 7 percent real discount rate per the U.S. Office of Management and Budget. (U.S. Office of Management and Budget, "Benefit-Cost Analysis of Federal Programs: Guidelines and Discount Rates," Curricular A94, in Federal Register 53(519), November 19, 1992.)

***The hydropower "head" is the distance that the water falls through the turbines--the higher the head, the higher the efficiency of the turbine.

****Capacity represents the ability to meet peak power demand.

## Appendix H

### Allocation of Flows to Meet San Joaquin River Standards

The DWRSIM and PROSIM hydrological models simulate the operation of a number of reservoirs to meet various flow and water quality standards in the Bay-Delta region. For the San Joaquin River basin, the sole reservoir simulated in either of these models is the U.S. Bureau of Reclamation's New Melones Dam on the Stanislaus River. If releases from New Melones are unable to meet San Joaquin River requirements, both PROSIM and DWRSIM assume that the additional flows will come from the Merced and Tuolumne Rivers (i.e., Lake McClure (a.k.a. Exchequer) and New Don Pedro Reservoir). This modelling has two important implicit assumptions that:

- the water rights holders on these two rivers will accommodate these flow increases by reducing their diversions in some unidentified manner; and

- these water rights holders, who are generally senior to the federal and state water projects, may be transferring water without compensation to those projects' contractors.

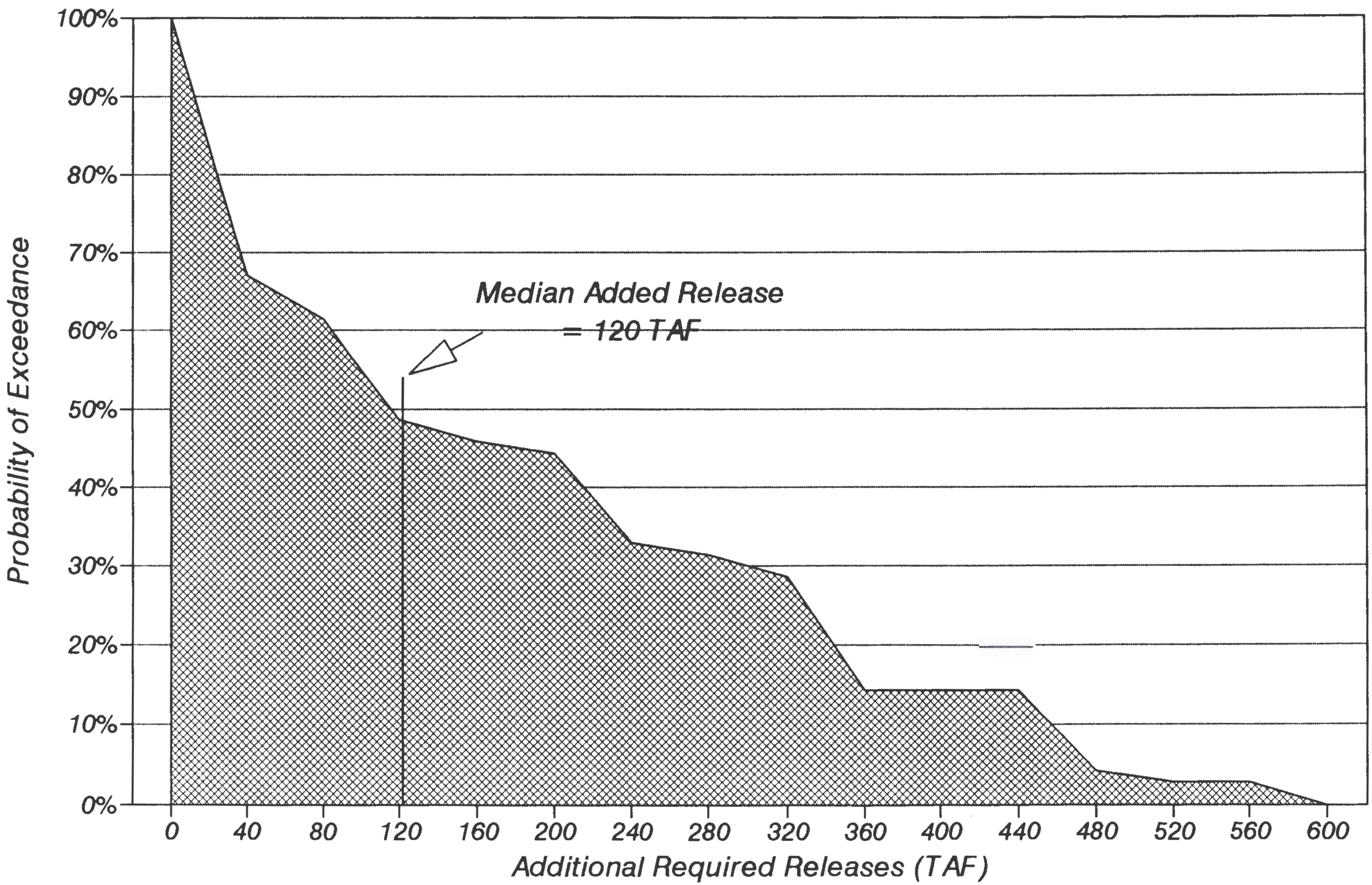
To evaluate the impacts on the Northern California generation system, changes in power generation with releases at Exchequer and Don Pedro should be estimated. The PG&EHELP model is created to accomplish this task. However, the large changes in releases assumed for these two projects create two problems. First, the large increases in flows in April and May cause larger swings in power generation for those two months than predicated in the model. But more importantly, the additional flows in April and May have no compensating decreases in releases in other months or surface water diversions elsewhere in the overall economic analysis being done by other analysts.

The increases in April and May flows from the PROSIM model for Alternative 1 (Proposed EPA standards) range from zero in one-third of the 70-year water history to nearly 300,000 acre-feet per month (equal to about 5,000 cubic feet per second (cfs)). The median level of releases is 60,000 acre-feet in each month, and the average over the 70-year period is 92,000 acre-feet per month. Figure H-1 shows the probability that certain additional releases in total for both months will be required. Figure H-2 shows how the added flows are distributed among historic Tuolumne River flows; the dark bars represent the additional flows needed to meet EPA standards. The figure shows that the increases tend to occur in drier years.

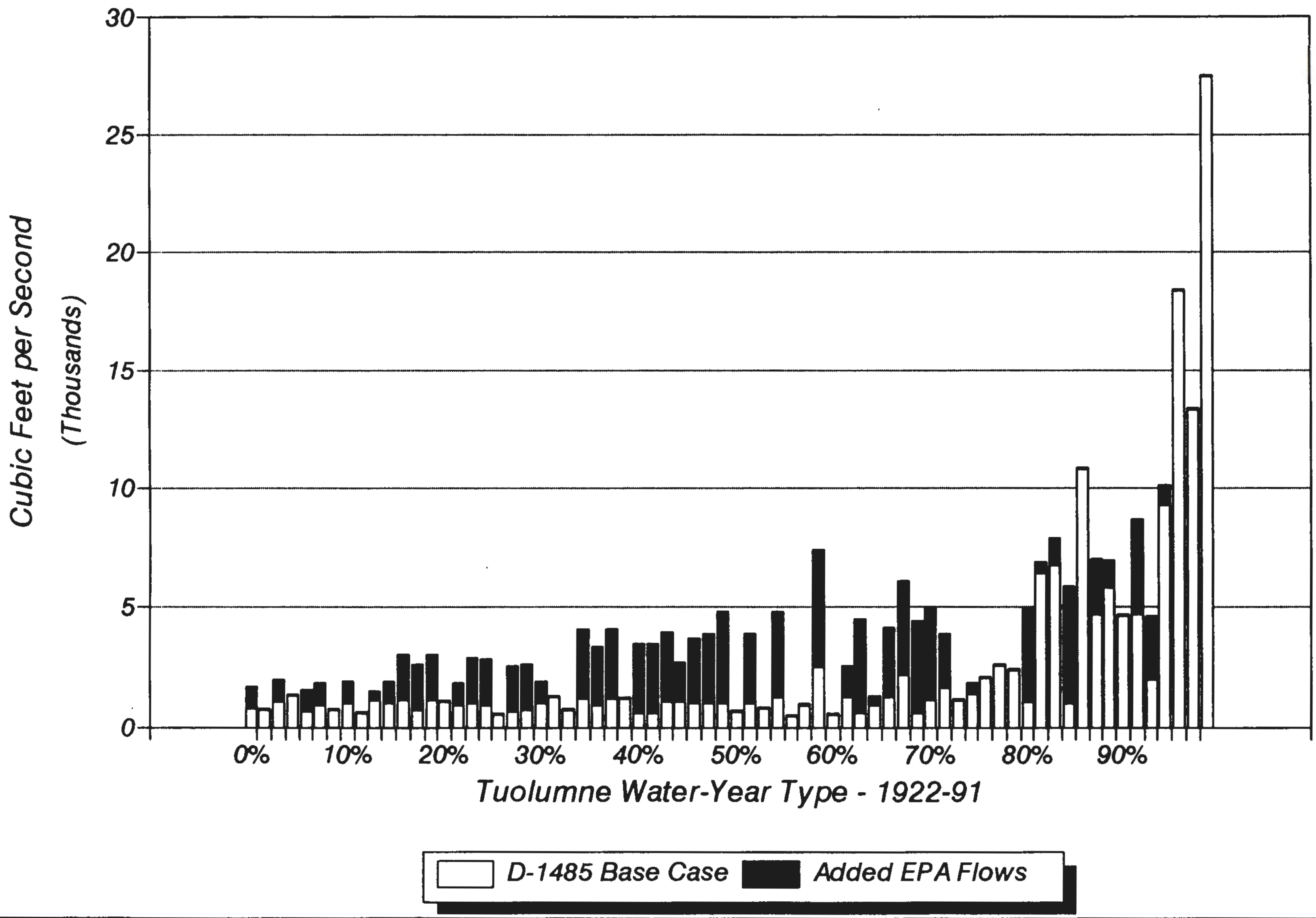
Neither the PROSIM nor the DWRSIM models reduce releases in other months because they do not have the operational rules for these reservoirs. The agricultural impact analysis currently being done by the EPA does not account for changes in water use or sources in these regions of the magnitude in the hydrological model results. Until an explicit and consistent assumption is made about the source of these additional water releases, the impacts on the hydropower system of these two rivers can not be estimated.

## Figure H-1

## Merced & Tuolumne Added Releases For April & May Under EPA Standards



# Figure H-2
## Merced & Tuolumne D-1485 & EPA Flows
## For April & May Over Water-Year Type



To properly model the electricity impact, these added flows must come from one of three sources:

- reduced releases in other months from reservoirs on these streams;
- reduced diversions for urban water use from the Hetch Hetchy system;
- reduced surface water use in the Merced, Modesto and Turlock Irrigation Districts; and/or
- replacement of this water with increased groundwater pumping.

In addition, the flows from the Merced and Tuolumne Rivers used to meet the Vernalis standards may become available for pumping by the Central Valley and State Water Projects. This occurs if the Delta outflow remain at the same level and the Delta exports are not reduced by the amount of the flows provided from the Merced and Tuolumne. The flows from these rivers then essentially replace Sacramento River water in the Delta outflow and the projects are relieved to some extent of their export restrictions. In other words if standards in the Delta do not require that the increased San Joaquin flows empty into San Francisco Bay, that water becomes available to the CVP and SWP.

A key issue is whether water made available to the CVP and SWP via meeting the Vernalis standards is viewed as abandoned or as an effective water transfer from the upstream districts to the Delta exporters. If the water is abandoned, compensation is not necessarily compelled, except possibly under the "takings" clause of the U.S. Constitution. If the availability of the water is made as a transfer, then the upstream diverters would be compensated by the downstream diverters. Resolution of this issue depends on how these property rights are interpreted in the state Water Code.

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